MINNESOTA POWER AND LIGHTISSUE DATE: MARCH 1, 1988
DOCKET NO: E-015/GR-87-223

FINDINGS OF FACT, CONCLUSIONS
OF LAW, AND ORDER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Barbara Beerhalter	Chair
Cynthia A. Kitlinski	Commissioner
Norma McKanna	Commissioner
Robert J. O'Keefe	Commissioner
Darrel L. Peterson	Commissioner

In the Matter of the Petition of Minnesota Power & Light Company, d/b/a/ Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota

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FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

PROCEDURAL HISTORY

On May 1, 1987 Minnesota Power & Light Company (Minnesota Power, MP, or the Company) filed a petition with the Minnesota Public Utilities Commission (the Commission) for authorization to increase its rates. The Company requested an annual rate increase of $4,353,474.

On June 1, 1987 the Commission accepted the filing, suspended the proposed rates, and began an investigation of the reasonableness of the proposed rates. On June 9, 1987 the Commission ordered contested case proceedings on the proposed rate increase under Minn. Stat. § 216B.16, subd. 1 (1986). The Office of Administrative Hearings assigned Administrative Law Judge Richard C. Luis to the case.

On June 30, 1987 the Commission set interim rates under Minn. Stat. § 216B.16, subd. 3 (1986). Interim rates were authorized as of July 1, 1987 and were set at a level allowing an additional $4,836,750 in annual revenues.

The Administrative Law Judge (ALJ) held a Prehearing Conference on June 19, 1987. There the parties and the ALJ identified the major issues, established procedural guidelines, and set timetables.

On July 10, 1987 the Commission issued a Supplemental Notice and Order for Hearing adding issues regarding "best efforts" marketing provisions in the Company's Large Power contracts to those under consideration in the case.

Intervenors

The following parties filed petitions to intervene in the case. The ALJ granted their petitions, making them parties in the proceeding.

Minnesota Department of Public Service (DPS)
Residential Utilities Division of the Office of the Minnesota Attorney General (OAG)
Senior Citizens Coalition of Northeastern Minnesota (Seniors)
Lake Superior Paper Industries (LSPI)
Companies Intervening Jointly, Designated Herein as Inland Group
- Inland Steel Mining Company (Inland)
- National Steel Pellett Company (National)
- Pickands Mather & Company (Hibbing)
- USX Corporation (USX)

Companies Intervening Jointly, Designated Herein as Superwood Group
- Superwood Corporation
- M.E. International
- USG Interiors, Inc.
- Hennepin Paper Co., Inc.
- Duluth Missabe and Iron Range Railway
- St. Gabriel's Hospital
- Independent School District No. 692
- Midwest Timber, Inc.
- Lyric Block Development Corporation
- Diamond Brands, Inc.
- Reach All, Inc.
- Upper Lakes Foods, Inc.
- Oneida Realty Company
- Land O' Lakes, Inc.
- Larson Boat Division of Genmar Industries, Inc.
- Hart Press

Potlatch Corporation (Potlatch)
Eveleth Taconite Company and Eveleth Expansion Company, d/b/a Eveleth Mines (Eveleth)
Boise Cascade Corporation and Blandin Paper Company (Boise/Blandin)

Public Hearings

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers at the following times and places. The numbers in parentheses show the number of people who attended each hearing; the numbers in brackets show how many people spoke.

August 17, 1987	Grand Rapids	(20)	[0]
August 18, 1987	Eveleth	(30)	[3]
August 19, 1987	Duluth (afternoon session)	(80)	[7]

August 20, 1987	Duluth (evening session)	(35)	[4]
August 24, 1987	Park Rapids	(12)	[2]
August 25, 1987	Little Falls	(12)	[2]

Evidentiary Hearings

The ALJ held evidentiary hearings in Duluth from September 28-October 2, 1987 and in St. Paul on October 5-9, 12-16, and 20-21, 1987. Appearances at the evidentiary hearings were as follows:

Paul A. Schweizer, Janet F. Gonzalez, Louis Sickmann, and David Jacobson, 780 American Center Building, 150 East Kellogg Boulevard, St. Paul, Minnesota 55101, for the Staff of the Public Utilities Commission;

Michael J. Bradley, Assistant Attorney General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, for the Residential Utilities Division, Office of the Attorney General (OAG);

Ann M. Seha, Special Assistant Attorney General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, for the Minnesota Department of Public Service (DPS);

Robert S. Lee and Vilis Inde, Mackall, Crounse & Moore, 1600 TCF Tower, 121 South Eighth Street, Minneapolis, Minnesota 55402, for those companies intervening jointly and designated herein as the Inland Group;

James D. Larson, Wurst, Pearson, Larson, Underwood & Mertz, 1100 First Bank Place West, Minneapolis, Minnesota 55402, for those companies intervening jointly and designated herein as the Superwood Group;

Laurence R. Waldoch, Lindquist & Vennum, 4200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402, for Potlatch Corporation (Potlatch);

James J. Ryan, Steer, Strauss, White & Tobias, 2208 Central Trust Tower, Cincinnati, Ohio 45202, and James W. Sanders, Assistant Secretary and Counsel, Oglebay Norton Company, 400 Superior Avenue, Cleveland, Ohio 44114, for Eveleth Taconite Company and Eveleth Expansion Company, d/b/a Eveleth Mines (Eveleth);

John A. Knapp, Winthrop & Weinstine, 1800 Conwed Tower, 444 Cedar Street, St. Paul, Minnesota 55101, for Boise Cascade Corporation and Blandin Paper Company;

Richard Baxendale, Associate General Counsel, Boise Cascade Corporation, One Jefferson Square, Boise, Idaho 83728, for Boise Cascade Corporation;

George M. Hoedeman, Hadlick, Hoedman & Christy, 2340 Dane Tower, Minneapolis, Minnesota

55402, for Lake Superior Paper Industries (LSPI);

Susan Ginsburg, 920 Alworth Building, 306 West Superior Street, Duluth, Minnesota 55802, for the Senior Citizens Coalition of Northeastern Minnesota (Seniors);

Samuel L. Hanson and R. Scott Davies, Briggs & Morgan, 2400 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402 and Douglas W. Peterson, Corporate Attorney, Minnesota Power, 30 West Superior Street, Duluth, Minnesota 55802, for Minnesota Power and Light Company (Minnesota Power, MP, or the Company).

Proceedings Before the Commission

The ALJ closed the record on January 7, 1988 and issued his report in two parts. The first was filed on January 19, 1988 and contained findings and recommendations on all issues except rate design and admission of testimony. The second was filed on January 22, 1988 and contained his findings and recommendations on those topics.

The Commission heard oral argument on Part I of the ALJ's Report on February 3, 1988 and on Part II on February 11, 1988.

At Oral Argument on Part II, the Commission requested comments on refund methodology by February 18, 1988.

Upon review of the entire record of this proceeding the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

I. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. §§ 216B.01 and .02 (1986). The Commission has specific jurisdiction over rate changes under Minn. Stat. § 216B.16 (1986).

The matter was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.57-l4.62 (1986) and Minn. Rules, parts 1400.0200 et seq.

The Commission gave proper notice of hearing in the matter, has fulfilled all relevant statutory and regulatory requirements, and has the authority to render a decision in this matter.

II. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7830.4100 any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of this Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. § 216B.27, subd. 3 (1986), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: 10 days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. § 216B.27, subd. 4.

III. MINNESOTA POWER

MP is an investor-owned electric utility providing electric service in an area of central and northeastern Minnesota covering approximately 26,000 square miles and 15 counties. The Company's electric service requirements and sales are dominated by large industrial customers, especially taconite producers in the Large Power class.

The climate of the service territory is cold in the winter and cool in the summer. Consequently, the utility has little summer air conditioning load. The Company also has little winter peaking, because so much of its load is in the Large Power class, where demand does not vary by season.

The Company's service area has undergone a significant economic recession since the Company's last general rate case in 1981. Taconite production has fallen sharply, causing widespread unemployment. Population has declined, and average household incomes have dropped. Overall demand for electricity has decreased.

IV. SUMMARY OF PUBLIC TESTIMONY

A great deal of public testimony was submitted in this case. One hundred eighty-nine people attended the public hearings. Fifty people submitted letters commenting on the proposed rate increase.

Two state legislators, Senator Ron Dicklich and Representative Joe Begich, appeared at a public hearing on behalf of the Iron Range delegation. That delegation included Senators Ron Dicklich and Doug Johnson and Representatives Joe Begich, Lona Minne, Loren Solberg, Dave Battaglia, and Tom Rukavina.

Thirteen municipalities in the Company's service area filed city council resolutions on the proposed rate increase: Cloquet, Iron, Mountain Iron, Kinney, Aurora, Hoyt Lakes, Leonidas, Keewatin, Meadowlands, Brookston, Nashwauk, Biwabik, and Buhl.

One coalition of Large Light and Power ratepayers, Minnesota Forest Industries, Inc., appeared, as did two individual Large Light and Power customers, Hennepin Paper and Hart Press.

The testimony from residential and small business ratepayers emphasized the economic difficulties in the Company's service area. They pointed to high unemployment rates, declining retail sales, business closings, and declining household incomes as evidence of their inability to absorb any rate increase resulting from this proceeding. They also asserted that the need for a rate increase was caused in part by the Company's over-building to serve large power users, who should bear the burden of any rate increase.

The city council resolutions emphasized the area's economic difficulties and the inability of local residents and businesses to absorb a rate increase. They also suggested that tax relief under the Tax Reform Act of 1986 and upcoming sales of capacity from Boswell 4 and Square Butte made a rate increase unnecessary. Finally, they stated that it is inappropriate for the Company to earn a rate of return substantially in excess of that earned by other Northeastern Minnesota businesses.

The Iron Range Delegation also emphasized the area's poor economy and the impact a rate increase would have on residential and small business ratepayers. They advocated examining rate increases in terms of their effects on the "main streets" and residents of Iron Range communities. They questioned the Company's need for a rate increase at a time when it was earning substantial profits and when it was about to receive substantial gains from the Boswell 4 and Square Butte sales, as well as tax relief under the Tax Reform Act of 1986.

The Delegation also stated that the Company filed the rate case in large part to reduce costs for the taconite companies. Representative Begich testified that these companies had received tax relief from the Legislature with the understanding that, among other things, they would not seek rate relief at the expense of the residential and small commercial classes. Representative Begich asserted that the taconite companies had reneged on this commitment.

Representatives of the Large Light and Power Class testified that the rate increases the Company proposed for them might inadvertently reduce the Company's revenues by leading Large Light and Power customers to construct their own hydro-generation or cogeneration facilities. This, of course, could result in higher rates for all customer classes. They also argued that businesses in the Large Light and Power Class were in no position to absorb the proposed rate increases.

V. BURDEN OF PROOF

A discussion of the burden of proof in ratemaking demands consideration of the quasi-judicial and legislative authority and responsibilities of the Commission, the types of facts involved, and finally the statutorily mandated public policy objectives.

The Minnesota Supreme Court in a recent decision <u>In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota,</u> 416 N.W.2d 719 (Minn. 1987) articulated standards for the burden of proof in rate cases. The Court found that when the Commission acts in its quasi-judicial capacity, it addresses basic facts and determines those facts by the civil court standard of a fair preponderance of the evidence. Examples of basic facts are amounts claimed, financial data reported, actions taken, words said, and phenomena perceived.

Building on those determinations, the Court found that the quantum of proof is not controlling and, therefore, the civil court standard is not directly applicable for the Commission to reach the ultimate findings of the reasonableness of rates. The Commission must determine whether the evidence presented even if true justifies the conclusion urged by a party. The Commission must make this decision in light of its statutory duty to enforce Minnesota's public policy that retail consumers of utility services have those services at reasonable rates. Minn. Stat. § 216B.01 (1986).

The types of facts the Commission addresses in this aspect of ratemaking are judgmental or inferred facts. Examples are whether an item is used and useful in providing utility service, evaluations of prudence in company decisions, the appropriateness and reasonableness of a rate case adjustment to rate base or income and expenses, and evaluations of investors' expectations of the cost of capital. Here the Commission must decide whether the character of a claimed amount is appropriate and whether ratepayers or shareholders should pay the cost.

The Commission must use its judgment and expertise in drawing inferences and conclusions from basic facts, rather than emphasizing the reliability of the facts themselves. In making judgmental findings, the Commission will necessarily rely in part on basic facts supported by a fair preponderance of the record evidence. In addition, however, the Commission will apply logical reasoning to those facts to insure just and reasonable rates for utility ratepayers.

Finally, the Commission also recognizes that Minn. Stat. § 216B.16, subd. 4 (1986) assigns the burden of proof to a utility when it seeks to change its rates. The utility has both the burden of coming forward with evidence to support its rate request and the continuing burden of persuasion throughout the rate case.

VI. TEST YEAR

MP proposed that the projected 12-month period ending June 30, 1988 be used as the test year in this proceeding. No party opposed the test year. The ALJ found that the test year chosen by MP is appropriate for this proceeding. The Commission agrees with the ALJ and will accept the test year proposed by MP.

VII. TWO REVENUE DEFICIENCIES

The Commission must decide whether it is appropriate to determine two separate final revenue deficiencies in this proceeding: one for the period that interim rates are in effect, and another for final prospective rates.

As indicated above, the test year for this proceeding is July 1, 1987 through June 30, 1988. Interim rates became effective on July 1, 1987, and will continue in effect until sometime after March 1, 1988. In its original filing, MP proposed an annual revenue deficiency of $9,604,578 for the interim rate period and $4,353,474 for final prospective rates. In its Order Setting Interim Rates, June 30, 1987, the Commission established an annual interim revenue deficiency of $4,836,750. The Company intended that the refund, if any, for the interim rate period would not be based on the final prospective revenue deficiency, but on a separately determined final interim revenue deficiency. MP stated that this proposal is necessary because many events occurring late in the test year will lower the revenue requirement. MP stated that this lower revenue requirement is appropriate for prospective rates, but not for interim rates, since the events causing the lower revenue requirement will not yet have taken place. MP stated that applying the lower prospective revenue requirement to the interim rate period would result in interim rates below the actual cost of providing service during the interim period.

The parties made no recommendations on this issue. The ALJ did not address this matter in his report.

MP essentially filed two separate rate cases in one proceeding, including two different allocated cost-of-service studies, two different rate bases, two different income statements, two different capital structures, and two different overall rates of return. The Commission finds that it is not being asked to make an adjustment for a single event, as it has done on occasion (e.g., Docket No. E-017/GR-86-380 (April 27, 1987)), but instead it is being asked to determine two separate rate cases within the statutory procedure and time frame established for one rate case.

Minn. Stat. § 216B.16 (1986) establishes the procedure for making rate changes. Generally, the utilities are allowed to change rates upon 60 days notice to the Commission. If the Commission suspends the implementation of the proposed rate schedule, it must implement interim rates within 60 days of the original notice. The Commission then has 10 months from the date of the original filing to determine proper final rates. The statute further provides that if final rates are lower than those allowed for the interim period, the utility must refund the amount collected during the interim rate period which exceeds the amount that would have been collected using the final rates. The Commission finds that this statute does not contemplate the determination of more than one final rate in determining the refund amount. Neither does it contemplate that the utility will file a rate request inadequate to meet its immediate needs, since, unless the Commission suspends the proposed rates, they go into effect 60 days from filing.

The alleged need for two separate revenue requirements arises, after all, primarily because of the timing of the filing. The timing of the filing was completely within the Company's control. Any shortfall allegedly resulting from the Commission's refusal to compute two revenue requirements could have been avoided by earlier, later, or more frequent filings. The Commission concludes that it is unreasonable and outside the intent of Minn. Stat. § 216B.16 to process two complete rate cases within a single proceeding.

VIII. TAX REFORM ACT OF 1986

MP included the effects of the Tax Reform Act of 1986 in this filing. Because those effects are included and reviewed in this proceeding, the Commission will not require MP to make filings under the Commission's permanent rules relating to rate adjustments due to the Tax Reform Act of 1986, Minn. Rules, parts 7827.0100 to 7827.0600.

IX. RATE BASE

MP's original filing calculated a revenue deficiency both with and without consideration of MP's proposed allowance for funds for plant being phased-out (AFPO). The Commission authorized the implementation of the AFPO method for ratemaking purposes in In the Matter of Minnesota Power & Light Company's Sale and Northern States Power Company's Purchase of Forty Percent Undivided Ownership Share in the Boswell Steam Electric Generating Station Unit No. 4 Facilities, Docket No. E-002, 015/PA-86-722 (June 23, 1987). No party opposed the AFPO methodology in this case. Therefore, the Commission will accept AFPO in this proceeding. All Commission adjustments will be based on MP's filing including AFPO.

In its initial filing, MP proposed an average rate base of $555,115,967 for the test year. In its July 23, 1987 supplemental filing, MP revised the amount of its proposed rate base to $551,126,873. The downward adjustment resulted from the new Minnesota income tax laws and the resulting changes in accumulated deferred taxes and cash working capital; from changes to correct an error related to recreational land leases; and from changes to correct an error related to fuel clause revenue.

Many of the intervenors and the ALJ used the supplemental rate base as a starting point. The Commission will also use this amount as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues will be discussed below.

A. Uncontested Adjustments

1. Cash Working Capital, Lead/Lag Study

MP included negative cash working capital of $20,217,190 in its supplemental filing. The DPS recommended an adjustment to this amount to reflect the accelerated payments of Boise Cascade and the removal of the Reserve Mining effect from the lead/lag study. MP agreed to the DPS proposal, reducing its cash working capital by $547,156 in its initial brief. The ALJ recommended the adjustment. The Commission agrees that the adjusted cash working capital more appropriately reflects MP's cash working capital needs.

The DPS and MP also included adjustments to cash working capital reflecting the effects of the income statement adjustments. The Commission will increase cash working capital by $592,787 to reflect the Commission's income statement adjustments, excluding the interest synchronization effects and the effects of the rate decrease ordered in this proceeding.

Consistent with prior Commission decisions, the Commission will include the cash working capital effects of the rate decrease and interest synchronization. In calculating the cash working capital effects of interest synchronization, the Commission first removed the effects already included by MP in the supplemental rate base by increasing cash working capital by the estimated amount of $33,810, then calculated the effects on an overall basis. The Commission finds that the net cash working capital impact of the decreased income taxes resulting from the rate decrease and the increased income taxes resulting from interest synchronization is a positive $6,565. Based on the above findings and calculations, the Commission concludes that the appropriate test year cash working capital is a negative $20,131,184.

2. Customer Deposits

MP did not exclude $343,751 of customer deposits from its rate base. The DPS, OAG, Inland Group, and the ALJ all recommended that amount be excluded from rate base. MP later agreed to the adjustment.

The Commission agrees that customer deposits must be excluded from rate base. Minn. Stat. § 216B.16, subd. 6 (1986), requires that rate base be offset by amounts of capital provided by sources other than investors. Customer deposits are ratepayer supplied funds, not investor supplied funds. This adjustment reduces rate base by $343,751.

3. Deferred Taxes on Unbilled Revenue

MP included accumulated deferred income taxes for unbilled revenue and for meters read but not billed in rate base. MP agreed with recommendations by the DPS, OAG, and the Inland Group to exclude the associated deferred taxes from rate base.

The ALJ also recommended that the accumulated deferred income taxes be removed from the rate base.

The Commission agrees with the parties and the ALJ that it is not appropriate to include the tax effects of unbilled revenue and meters read but not billed in rate base when the ratepayer has not had the benefit of the related revenues. This adjustment reduces rate base by $1,177,035.

4. Deferred Taxes on Butler Settlement

MP included accumulated deferred income taxes on the Butler settlement in rate base. MP agreed with the DPS and the Inland Group to exclude the amount from rate base.

The ALJ recommended that the accumulated deferred income taxes related to the Butler settlement be removed from rate base.

The Commission agrees with the parties and the ALJ that it is not appropriate to include the tax effects of the Butler settlement when ratepayers are not receiving the benefit from the settlement in final rates. Ratepayers should not be required to pay what amounts to a carrying charge on the income tax effects when they are no longer receiving the benefit of the related revenue. This adjustment reduces test year rate base by $1,086,149.

5. Deferred Taxes on Erie/Reserve Debt Reserve

MP excluded revenues and expenses from the test year for the amount of Reserve revenues not yet received. However, MP included those amounts in taxable income, resulting in an adjustment to deferred taxes. The DPS and the Inland Group recommended that the tax effect be removed from the deferred taxes. MP agreed with this recommendation.

The ALJ recommended that the Commission exclude the deferred income taxes associated with Reserve's bad debts from the rate base.

The Commission agrees with the parties and the ALJ that the inclusion of the deferred taxes on the Reserve bad debts results in an inappropriate increase in rate base which should not be allowed. This adjustment reduces rate base by $3,100,493.

6. Accumulated Deferred Income Taxes

MP proposed to return the excess deferred income taxes which resulted from the reduction in the federal income tax rates from 48% to 46% in 1979. In addition, MP proposed to return those excess deferred income taxes resulting from the Tax Reform Act of 1986 and which are not protected by Section 203 (e) of that act. MP proposed to return the excess deferred taxes over an amortization period of two years. MP's proposal, as included in its original filing, increased rate base by $1,916,766 and increased test year net operating income by $3,833,531.

The OAG recommended the acceptance of MP's proposal. The ALJ did not address this item.

The Commission accepts MP's proposal. Returning the excess deferred income taxes over a two-year period is equitable since an accelerated return of the excess is more likely to return the excess to those who paid it, while the funds still have some of their original value. The Commission has made several similar adjustments in rate cases since 1982, including: <u>Northwestern Bell Telephone Company</u>, Docket No. P-421/GR-82-203 (April 20, 1983); <u>Northern States Power Company</u>, Docket No. G-002/GR-86-160 (January 27, 1987); and <u>OTP</u>, E-017/GR-86-380. MP has included the financial adjustments in its original filing. Therefore, no adjustments are needed to incorporate the Commission's acceptance of MP's proposal.

B. <u>Hibbard Boiler Amortization</u>

Two issues raised by the parties regarding the Hibbard station involved the inclusion of Hibbard boilers 3 and 4 in the test year and the appropriate depreciation rate for the entire Hibbard station.

The Commission will first address the issue of whether MP should be allowed to include the unamortized balance of Hibbard boilers 3 and 4 in rate base and to recover the boiler investment through an amortization to test year expense.

MP transferred Hibbard boilers 3 and 4 to the City of Duluth on December 2, 1985. MP recorded the unamortized balance remaining at the time of the transfer as a miscellaneous deferred debit. MP proposed that the remaining deferred balance be included in rate base as an investment in steam supply and proposed to include an amortization to test year expense.

The DPS, OAG, and the Inland Group recommended that MP's proposed inclusion of the unamortized balance and amortization to expense for Hibbard boilers 3 and 4 be disallowed.

The ALJ recommended that the unamortized balance for Hibbard 3 and 4 be excluded from rate base and the expense amortization be excluded from test year expenses.

The Commission rejects MP's arguments that because the Hibbard boilers were once owned by MP and were once "used and useful" in the provision of utility service, they must be allowed recovery even though the property was donated to the City of Duluth. The Commission finds many considerations at work here. The boilers were given away, not retired. The donation of the boilers to the City of Duluth will result in lower-cost power for LSPI, in which MP has a substantial financial interest. The donation will be helpful in the economic development of the City of Duluth. MP stated that it will purchase excess steam from the City of Duluth at a future date, which is likely to further benefit LSPI through a lower price for steam. The Commission is not convinced that the donation of boilers 3 and 4 was made in the best interest of the ratepayers. The Commission finds that the ratepayer should not be asked to provide a return on and a recovery of property which is utilized to the benefit of the City of Duluth and MP's shareholders through its non-utility interest in LSPI.

The Commission accepts the arguments made by the parties and recommended by the ALJ that ratepayers should not be required to provide a return on and a return of property not owned by the utility. Minn. Stat. § 216B.16, subd. 6 (1986) provides that:

> The Commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

The Commission finds that the boilers are not owned by the utility and are not used and useful in providing utility service. Rather, the boilers have been donated by the shareholders to the City of Duluth, where the record shows they will be used in providing services useful to the development of the City of Duluth and the shareholders' other project, LSPI.

Therefore, the Commission will disallow rate base treatment and the amortization to expense of Hibbard boilers 3 and 4. This adjustment reduces rate base by $384,812. The expense effects will be described under the income statement section of this Order.

Next, the Commission will determine whether the depreciation rate should be adjusted for the entire Hibbard station.

MP computed depreciation on the Hibbard station and boilers 3 and 4 based on its last Commission certified rates. This represents a residual useful life of approximately 4.5 years. MP argued that no changes were necessary.

The OAG recommended that the useful life be extended to 22 years, resulting in a considerably lower test year depreciation rate for Hibbard.

The ALJ recommended that the test year depreciation expense for Hibbard be adjusted to reflect the 22-year useful life.

The Commission rejects the recommendation of the OAG and the ALJ to extend the useful life of the Hibbard unit to 22 years in this proceeding. The Commission finds that additional investment is necessary in the Hibbard station before its useful life will be extended. Further, after the investment is made, the new life must be determined and certified by the Commission. Therefore, the Commission will not adjust the useful life for depreciation purposes in this proceeding.

C. Excess Capacity

The issues before the Commission are whether MP currently has capacity in excess of its needs and whether a downward adjustment in rate levels should be made to recognize that excess.

The DPS, the Inland Group, and the Superwood Group all argued that MP has excess capacity and that an adjustment should be made to recognize that excess. Excess capacity levels of 250 megawatts (MW) to 440 MW were suggested by those parties. MP argued that it has no excess capacity considering required reserve margins, inter-utility sales, plant capacity factors, plant operating costs, and other factors. Further, the Company argued that its generating facilities were prudently constructed and are used and useful.

The ALJ agreed with the Company. He emphasized that the Company had acted prudently, that any short-term capacity surplus was due to economic conditions the Company was unable to control or predict, and that the Company was in the process of reducing capacity through its Boswell 4 and Coyote sales.

The Commission has carefully examined the record on this issue. The Commission agrees with the ALJ that the Company acted prudently in acquiring its current capacity and that the Company could not reasonably have predicted the economic downturn which has severely curtailed demand in its service area. The Commission does not believe that any excess capacity on the Company's system is the result of mismanagement or imprudence.

Nevertheless, the Commission concludes that there is excess capacity on the Company's system. The Commission also believes that equity and sound public policy require that the shareholders, as well as the ratepayers, bear part of the costs associated with the maintenance of this excess capacity.

The issues remaining are how much of the system's capacity is excess and what is an appropriate mechanism for translating that excess into rate reductions. The Commission will first determine the amount of the excess and then determine the appropriate remedy. Finally, the Commission will explain in more detail its reasons for rejecting the Company's position that the AFPO eliminates any need for an excess capacity adjustment and the DPS position that the excess capacity is the result of imprudence.

1. The Amount of the Excess

First of all, it is helpful to note that each of the intervenors recommending an excess capacity adjustment would have found approximately the same level of excess in the test year if they had used the same assumptions in three areas: reserve margin, treatment of the Coyote and Hibbard plants, and treatment of inter-utility sales.

With respect to reserve margin, the Commission finds that 15% is the minimum reserve margin that utilities must maintain to meet the reliability criterion of the Mid-Continent Area Power Pool (MAPP). However, the Commission finds that the combined effects of MP's high load factors and the requirement for economical operation imply that a higher reserve margin is in the best interests of the Company's ratepayers. The ALJ indicated that a 25% reserve margin is reasonable and appropriate for MP's system. For purposes of this case, the Commission accepts a 25% reserve margin as reasonable.

The Commission agrees with MP and the ALJ that the Coyote facility should be excluded from excess capacity computations. MP has sold its share of the plant and no costs related to Coyote have been included in the Company's filing for prospective rates. The Commission also concludes that capacity from Hibbard 3 and 4 should be excluded from the computation. Ownership of the Hibbard boilers 3 and 4 has been transferred to the City of Duluth. Ratemaking treatment of the Hibbard boilers 3 and 4 is discussed as a separate issue in this Order.

However, with the possible exception of 30-40 MW of Boswell 3 and 40 MW from the Erie plant, the Commission rejects the suggestion that there should be separate removals of other existing capacity before making the excess capacity calculation. The ALJ implicitly made such removals in his arguments, and that is the major reason why the Commission disagrees with the ALJ's analysis of this issue. MP, like every other utility, has a mix of capacity with varying ages, fuel types, efficiencies, and reliability factors; the selected reserve margin already takes this fact into consideration. Further, it is illogical to argue that a plant should not be considered in determining excess capacity because it is not used extensively when a key reason for lack of use is the existence of surplus capacity. The Commission believes that MP's arguments for removing capacity from the calculations may be more relevant in deciding which capacity should be considered excess.

If the Commission were also to disallow consideration of inter-utility sales in the computation, calculations would show maximum excess capacity on MP's system of approximately 270 MW during the test year.

The major reason the Commission cannot accept the computations of the intervenors is that they do not reflect adjustment of supply and demand figures to recognize certain types of revenue received by the Company. These include revenues from inter-utility sales and from demands by customers beyond the levels included by MP in its submissions to MAPP. Customers of MP cannot expect to receive credit for those additional revenues in ratemaking without recognizing the capacity commitment necessary to make such revenues possible.

Some of the intervenors have argued that inter-utility sales should be ignored entirely in the excess capacity determination. However, even if inter-utility sales were priced at the cost of Boswell 4 or the current power pool rates, the minimum base-load capacity necessary to generate the sales revenue included by MP in its filing would be about 20 MW. The Commission finds that the Large Power revenues accepted in this Order cover another 130 MW of capacity. Therefore, the Commission finds that recognition of these two types of revenue reduces the effective excess on the system by approximately 150 MW.

Finally, the Commission finds that it is difficult to determine whether the excess capacity calculation should reflect a derating of the base-load Boswell 3 facility by 30-40 MW and the removal of 40 MW of standby capacity from the Erie plant. During normal operation, Boswell 3 is limited to 310-320 MW to minimize slagging and backpressure problems. Also, the capacity figures used by the parties include upward reratings of capacity by 73 MW, indicating that equity considerations might imply that this derating should also be included.

With respect to the Erie plant, the Commission notes that it is owned by another company and has not been operated for several years. In addition, no net energy is available to MP from the plant under its agreement with LTV Steel Mining Company. MP could not plan on a long-term energy supply from this plant without negotitating a new contract with LTV Steel Mining Company.

Neither of these two capacity sources, then, is clearly and unequivocally available for regular use. At most, this combined 70-80 MW from the Boswell 3 and Erie units should be regarded as peaking capacity.

The Commission concludes that MP currently has approximately 40-120 MW of excess capacity on its system. The Commission believes that this level represents a balanced, objective analysis of the conflicting evidence presented by the parties, taking into account the decisions on other issues in this rate case.

Given this level of excess capacity, the Commission must next determine an appropriate ratemaking remedy for the problem.

2. Consequences for Ratemaking

From its analysis of the facts in this case, the Commission concludes that any excess capacity adjustment should focus on the Company's older oil-fired capacity. MP's high system load factors result in a need for plants which can provide economical, reliable power and energy 24 hours a day on a year-around basis. Because of the nature of its customer base, MP has less seasonal and time-of-day variation in demand, and therefore has less need for low-efficiency peaking plants, than most utilities its size.

Given this fact, the Commission believes it would be unfair and illogical to base an excess capacity adjustment on those plants with low operating costs and high capacity factors. Such plants are the most used and most useful to ratepayers of any owned by the Company.

However, MP also has on its system a substantial amount of capacity suitable primarily for peaking purposes. With the exception of the Company's low-cost hydro facilities, MP's peaking capacity primarily uses oil, which is a relatively expensive fuel. This oil-fired peaking capacity currently has value to MP's ratepayers only to the extent that it is necessary to meet load. As discussed above, peaking capacity is less useful to MP than to many utilities its size.

MP testified that the oil-fired Hibbard facility "has been in an inoperable state for several years" and that the facility is not scheduled for operation during the test year. In addition, the facility is not currently accredited by MAPP. While MP has long-term plans to reactivate the plant, those plans are tentative and unrelated to current needs of the system. This plant then would be a candidate for exclusion as not used and useful even if the Commission had not made a finding of overall excess capacity on the system. Furthermore, the capacity of that facility is reasonably close to the amount of excess capacity on the system.
From the foregoing facts, the Commission concludes that the appropriate ratemaking remedy to MP's excess capacity problem is removal from rate base of that part of the Hibbard facility not removed in conjunction with the boiler transfer to the City of Duluth, and removal of associated expenses from operating expenses. This decision reduces steam plant by $10,185,746 and accumulated depreciation by $8,471,802, for a net rate base reduction of $1,713,944. The income statement effects of this adjustment will be discussed in the income statement section of this Order.

3. The Relationship Between the AFPO Credit and Excess Capacity

In reaching this decision, the Commission does not accept MP's argument that bringing forward the gain on the Boswell 4 sale, through the AFPO credit, negates the need for any excess capacity adjustment. The Commission believes that any gain from the sale of utility property properly belongs to the ratepayers. Thus, at most, MP's argument is that crediting the sale benefits to ratepayers before the sale actually takes place ameliorates the need for an excess capacity adjustment. The Commission does not agree that the two are logically connected.

The AFPO credit was proposed as a mechanism for levelizing the various revenue effects of the sale of Boswell 4 and not as a remedy for offsetting the effects of excess capacity. In <u>In the Matter of Minnesota Power & Light Company's Sale and Northern States Power Company's Purchase of Forty Percent Undivided Ownership Share in the Boswell Steam Electric Generating Station Unit No. 4 Facilities</u>, Docket No. E-002, 015/PA-86-722 (June 23, 1987), MP agreed to the proposed AFPO treatment in a stipulation which also explicitly acknowledged the right of intervenors to raise the excess capacity issue in this rate case. The Commission accepted that stipulation, including its reservation of the excess capacity issue, as the basis for approving the sale and lease agreements between MP and Northern States Power Company (NSP).

4. The Issue of Prudence

By its excess capacity adjustment, the Commission is not making any finding of imprudence on the part of MP in constructing the Boswell 4 facility or in dealing with its excess capacity problem.

In this rate case, only the DPS suggested that an excess capacity adjustment should be based on a prudence analysis. The DPS argued that the Company was imprudent in its failure to 1) undertake risk mitigation measures in addition to the take-or-pay contracts with Large Power customers before the Boswell 4 facility was constructed and 2) correct its excess capacity problem in the early 1980s.

The Commission cannot agree with the arguments of the DPS regarding the construction of Boswell 4. Several regulatory agencies, including this Commission, determined that the construction of Boswell 4 was prudently undertaken. Furthermore, the risk mitigation measures suggested by the DPS would have been extraordinary in the mid-1970s. The Commission cannot conclude that MP could reasonably have been expected to adopt such measures, given the circumstances which existed when Boswell 4 was planned and constructed.

Further, the Commission finds that the Large Power contracts negotiated by the Company have afforded a substantial amount of revenue protection to MP and its ratepayers. The importance of those contracts to ratepayers should be recognized.

The Commission also cannot agree with the arguments of the DPS regarding MP's actions during the early 1980s. The evidence in this case simply does not support the contention that MP could and should have sold equity interests in its facilities in the early 1980s. With the exception of Northeastern Minnesota Municipal Power Agency (NEMMPA), there is no indication that other utilities were interested in purchasing capacity from MP. Further, there is no assurance that NEMMPA would have accepted an offer to purchase 75 MW of Boswell 4 at book value. In addition, such a sale by MP would not have significantly affected MP's excess capacity situation, because NEMMPA was already buying power from MP. Finally, even if any sales were possible, the alleged sales opportunities arose at a time when MP was understandably uncertain that the declines in taconite production were permanent.

Considering the record as a whole, the Commission rejects the argument that an excess capacity adjustment should be based on a prudence analysis.

D. <u>Rate Adjustments for Boswell 4 and Square Butte Sale</u>

The Commission must decide whether to order rate adjustments in this proceeding to be in effect on each of the future Boswell 4 and Square Butte transfer dates.

MP has entered into a sale agreement with NSP in which 40% of Boswell 4 and approximately 100 MW of Square Butte capacity will be transferred to NSP. The sale will take place with one-third being transferred to NSP in May 1989, May 1990, and May 1991. MP argued that no adjustments to rates for these transfers are necessary in this proceeding.

If the Commission did not accept its excess capacity position, the Superwood Group recommended that the Commission order rate adjustments to recognize MP's reduced rate base and operating costs on each of the Boswell 4 and Square Butte sale transfer dates. The Superwood Group argued that the future rate base reductions should be incorporated into rates resulting from this proceeding in a manner similar to how the Tax Reform Act of 1986 was incorporated in OTP, E-017/GR-86-380.

The ALJ recommended against adopting the Superwood Group's recommendation.

The Commission agrees with the ALJ's recommendation. While the Boswell 4 and Square Butte sale is a known and measurable change which could be incorporated into this proceeding, the Commission finds that the proposal is inconsistent with the Commission's Order Approving Transfer of Property and Ratemaking Treatment, June 23, 1987, and the Commission's Order for Investigations, June 23, 1987, in NSP, MP, E-002,015/PA-86-722. The Commission finds that the investigations ordered on each of the transfer dates, together with MP's commitment to make rates subject to refund at each of the transfer dates, assures ratepayers of fair and reasonable rates after the transfers.

Although the Commission agrees with the ALJ's recommendation and reasoning that the Superwood Group's proposal is inconsistent with the Commission's earlier Order in NSP, MP, E-002,015/PA-86-722, the Commission does not accept the ALJ's reasoning regarding piecemeal ratemaking. The Commission maintains that the known and measurable transaction could have been considered in this rate case proceeding, and would not constitute piecemeal ratemaking since all parties have had the opportunity to review and make recommendations regarding the associated costs. Further, MP would have had the opportunity to file a future rate case should its costs change.

The Commission concludes that, although it could have set rates to be effective on each of the future transfer dates, no such adjustments are necessary in this proceeding. Ratepayers have already been afforded adequate protection in the sale docket.

E. Rate Case Expense

As discussed in the operating income statement section of this Order, the Commission extended the amortization of the rate case expenses from a two-year period to a three-year period. The Commission also reduced the inflation factor utilized by MP in projecting its rate case expenses from 5.5% to 3.81%. In addition to the changes in test year expense, these adjustments result in an increase in test year rate base of $83,793.

F. Allocation Effects on Change in Billing Units and Revenues

The Commission made several adjustments to test year revenues in the billing units and retail rate revenues section of this Order. As discussed in that section, the adjustment to retail revenues results in a change in jurisdictional allocation factors. The Commission will reduce rate base by $298,424 to reflect the estimated effect of the change in allocation factors.

G. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $543,192,064, as shown below.

Utility Plant in Service	$939,761,794
Less: Accumulated Depreciation	(267,059,740)
Net Utility Plant in Service	$672,702,054
Construction Work in Progress	$ 16,202,859
Accumulated Deferred Income Taxes	(145,561,985)
Customer Advances	(685,176)
Customer Deposits	(343,751)
Miscellaneous Deferred Items	589,060
Working Capital:	
Cash Working Capital	$(20,131,184)
Materials and Supplies	2,579,023
Fuel Inventory	17,231,169
Prepayments	609,995
TOTAL RATE BASE	$543,192,064

X. OPERATING INCOME STATEMENT

In its July 23, 1987 supplemental filing, MP proposed test year net operating income of $49,396,409, based on total revenues of $328,239,881. Individual income statement issues will be discussed below.

A. Uncontested Adjustments

1. Ongoing Conservation Expenses

MP included $97,563 as estimated test year expenses for its conservation improvement program (CIP). MP proposed a tracking account and balancing system similar to that approved in Northern States Power Company, Docket No. E-002/GR-85-558 (June 2, 1986).

The DPS agreed with MP's proposal. The ALJ recommended the adoption of the proposed deferred debit accounting method.

The Commission agrees that the proposed deferred debit accounting method is appropriate since it is the most equitable method to accomplish the objective of allowing the Company to recover prudently incurred expenses for conservation projects authorized by the Commission or required by the federal government. Deferred debit accounting also ensures that ratepayers pay only for costs actually incurred by the Company for such programs. Rates set in the general rate case include an estimated amount for CIP expenses. However, under CIP rules, the Commission can accept, reject, or modify MP's programs for conservation expenditures. This review process can result in significant deviations from the CIP expenditure level authorized in a general rate case.

The Commission will require the Company to keep a record in a separate "tracker" account of the amount of conservation costs recovered from ratepayers through rates and the amount actually spent on conservation programs. The difference will accumulate in the tracker account until MP files its next rate case, at which time MP may request recovery of any unrecovered amount or must return any overrecovered amount. The difference between conservation costs recovered from ratepayers and the amount actually spent in the tracker account is to be accounted for by the Company as a deferred debit or credit. Recovery will be limited to prudently incurred costs associated with conservation projects approved by the Commission or required by the federal government.

No carrying charge is to be applied to the tracker account balance. For the Commission to monitor the amounts in the tracker account, the Company will be ordered to file annual reports. For this annual report to more appropriately reflect the annual CIP cycle, the Commission will require the first report to reflect 15 months, from July 1, 1987 through September 30, 1988 with the information for July through September 1987 broken out separately. This report will be due on or before January 1, 1989. Annually thereafter, MP will be required to file its annual report on or before each January 1, for the 12-month period ending the preceding September 30.

The costs to be included in the tracker account are those costs incurred by MP beginning July 1, 1987. The costs in the tracker account must be separately identified by project. The offsetting amount collected through rates (the revenue recovery amount) to be included in the tracker is to begin with the effective date of interim rates in this case. The revenue recovery amount is calculated by multiplying the actual sales beginning with the effective date of interim rates in this case by the recovery rate allowed in the test year. The recovery rate shall be calculated by dividing total test year sales volumes, as approved by the Commission in this case, into the allowed test year expense.

The Commission also agrees that the proposed $97,563 amount is a reasonable estimate of CIP expenses for the test year. The Commission recognizes that this amount approximates the amounts historically expended by MP for CIP projects.

2. FERC Audit

MP included litigation expenses totalling $1,018,993 in its fuel adjustment clause over the years 1978 through 1985. The litigation involved attempts to recover Montana coal severance taxes and litigation of the railroad coal transportation tariff before the Interstate Commerce Commission. In May, 1987, the Federal Energy Regulatory Commission (FERC) issued a decision in its Docket No. FA-84-15-000 indicating disagreement with MP's treatment of the litigation expenses. MP stated that it was still appealing the FERC decision and that no adjustment should be made regarding this matter until the matter is final before FERC. MP proposed that this matter be addressed in a separate docket at a later date.

The DPS and the ALJ agreed with MP and recommended that MP be ordered to file a compliance filing with the Commission after the final FERC ruling is received.

The Commission agrees that it is more appropriate to address this matter in a separate proceeding after the FERC issues its final decision. Deferring action on this matter requires no financial adjustment in this proceeding because this matter involves an automatic fuel adjustment which took place prior to the test year.

3. Investment Tax Credit Related to Coyote Sale

MP included $1,369,721 as other revenue in the test year. This revenue represents the gain on the final installment of the sale of MP's 5% interest in the Coyote generating station. The final installment of the sale is expected to take place in May 1988.

In addition to the gain on the sale of the Coyote generating station, MP originally included the accumulated investment tax credits (ITC) related to the final portion of the Coyote generating station, amortized over two years. This action increased test year net income. However, during the evidentiary hearings, MP received information from the Internal Revenue Service (IRS) indicating that MP must write off the unamortized ITCs at the time of the sale, and cannot pass the unamortized ITCs through to ratepayers. As a result, MP proposed to remove the Coyote ITC flowback from the income statement. This action decreases MP's test year net operating income by $328,517.

No party expressed opposition to MP's adjustment removing the Coyote ITC flowback. The ALJ recommended that the adjustment be adopted.

The Commission agrees that, based on the evidence in this record, MP should not flowback the unamortized Coyote ITCs, since doing so may jeopardize the approximately $49 million in ITCs still before the IRS. This would clearly be contrary to the ratepayers' interests.

4. Recreational Land Leases

MP reduced test year revenues by $595,639 in its July 23, 1987 supplemental filing. MP stated that this adjustment corrected the amount of recreational land lease revenue, from recreational land located along its reservoir system, included as test year revenues.

The OAG agreed that the adjustment was necessary to properly match the recreational land expenses included as test year expenses with the proper amount of revenue. The ALJ did not address this issue.

The Commission agrees that, in order to achieve proper matching, the portion of expenses included for the test year should be matched with an equal portion of revenues. This adjustment is included in the supplemental filing. Therefore, no adjustment is required to reflect this decision.

5. Charitable Contributions

MP included $16,558 in test year expenses representing the salaries of executives loaned to the United Way.

The DPS, OAG, and the ALJ recommended that 50% be disallowed under Minn. Stat. § 216B.16, subd. 9 (1986). MP agreed with this recommendation.

The Commission agrees that 50% of this contribution must be excluded from test year expense under Minn. Stat. § 216B.16, subd. 9 (1986). This adjustment reduces test year expense by $8,279, increasing test year net income by $4,945 after tax effects.

6. Automatic Tax Adjustment

MP originally proposed an automatic adjustment provision to allow tax changes to be passed through in rates. MP stated such a provision would eliminate the necessity for a general rate case every time the tax law changed. MP recommended that the FERC formula method be adopted. This proposal included no test year financial effects because the test year was already adjusted for the effects of the Tax Reform Act of 1986 and the 1987 changes in Minnesota tax law.

The DPS stated that this issue would be more appropriately addressed in a separate proceeding. The Inland Group stated that such an adjustment clause is unnecessary. MP later agreed with the DPS.

The ALJ recommended that the matter be addressed in a separate generic docket.

The Commission agrees that it would be inappropriate to establish an automatic tax adjustment methodology in a general rate case affecting only one utility.

7. Interest on Customer Deposits

As discussed in the rate base section of this Order, the Commission excluded customer deposits from the rate base. The Commission will allow MP to recover the interest paid on the deposits by including the interest paid as a test year expense. Such payments are required by Commission rule and are directly related to the provision of utility services. Minn. Rules, part 7820.4500, subp. 1. This adjustment was agreed to by the parties and recommended by the ALJ. This adjustment increases test year expenses by $20,105 and reduces net income by $12,009 after tax effects.

B. <u>Billing Units and Retail Rate Revenues</u>

1. Background

The Commission must determine appropriate billing units and operating revenue for use in the revenue requirements determination.

a. The Company's Forecast

The source of MP's projected billing units for this case was the Company's Sales Budget, prepared by the Marketing Department. The Sales Budget provided estimates of demand and energy sales, as well as the expected numbers of electric customers for the two-year budget period applicable to this case (i.e., 1987 and 1988). MP based its revenue budget upon these sales and customer estimates, using applicable rate schedules.

In making their estimates, Company personnel analyzed historical data and prepared growth trends. General economic conditions, housing starts, weather, labor climate, and steel shipments were some of the variables considered.

Many utility expense items vary with sales levels. Once the energy sales levels were set, MP established a schedule for Company-generated, purchased, and interchange power, based upon generation efficiencies, availability rates, and outage rates for its generating units. Fuel expenses for Company generation were based upon anticipated fuel receipts, delivered fuel prices, and resulting inventory levels.

In converting the budget figures to test year estimates, the Company made certain minor adjustments to reflect known changes, such as a change in a customer's billing category. Resulting billing units and sales revenues for the test year as proposed in the filing are given below:

Rate Category	MWH	Revenue ($)
Residential	732,645	40,398,400
General Service	471,171	28,626,500
Large Light & Power	747,268	35,274,200
Large Power	3,820,331	178,769,100
Municipal Pumping	48,053	2,375,100
Lighting	22,616	2,830,900
Totals	5,842,084	288,274,200

b. The DPS Forecast

As a check on the Company's forecast, the DPS prepared independent estimates of test year demand and energy sales. The DPS used the sales data MP assembled for its long-term forecast. Those data were divided by the Company into six categories: Residential, Commercial, Mining, Wood, Other Industrial, and Other. (These groups did not necessarily correspond to rate classes.) The figures provided by the Company for the Residential and Commercial categories were further divided into the three Divisions (i.e., Northern, Western, and Central).

For the large customers in the Mining and Wood categories, the DPS used test year estimates provided by the individual customers. For the balance of the customers in the category, the DPS used the Company's sales estimates. The DPS testimony indicated major differences between its estimates and those of the Company for Eveleth Mines (Eveleth), Inland Steel Mining Company (Inland), and Hibbing Taconite Company (Hibbing). These differences will be discussed in detail below.

To forecast sales in the other categories, the DPS used econometric models or accepted the Company's estimates.

The resulting total sales projected by the DPS were somewhat higher than the Company's original estimate. Because the forecasting categories do not correspond to rate categories, the DPS was not able to calculate the exact financial effect of its higher sales forecast. However, the financial impact of the difference in energy sales would have been relatively small, because most of the difference was in the Large Power class, for which the margin is very small. As a result, the DPS recommended changes in billing units and associated revenues only for specific customers in the Large Power class.

Based on the testimony of MP and the DPS, the Commission accepts the test year billing units of the Company, except as discussed below for Large Power customers.

2. Sales to Eveleth

Under its current contract with MP, Eveleth has a contract demand of 78.375 MW. When the Company prepared its filing for this proceeding, it assumed that Eveleth would accept a contract extension offer which included a contract demand reduction of 18%. As a result, MP used 63.525 MW as Eveleth's contract demand level for the test year in its filing. As of the time of the hearing, Eveleth had not agreed to the contract extension. The DPS argued that the greater level of contract demand during the test year would produce additional demand revenue that should be reflected in operating revenue for purposes of this rate case. The DPS also indicated that, if Eveleth and MP agreed on a new contract demand level before the end of this proceeding, the test year revenue forecast for Eveleth should be revised accordingly. The OAG, Eveleth, and the Inland Group all indicated their agreement with the DPS proposal for Eveleth. MP indicated that it accepted the DPS demand adjustment, subject to appropriate modification if a new agreement was reached with Eveleth prior to March 1, 1988.

On January 14, 1988, MP filed for Commission approval a new contract amendment for sales to Eveleth. The new agreement specifies a contract demand level of 61.64 MW from May 25, 1987 through October 1987 and 56 MW thereafter. The agreement also contains a contract buy-down provision providing for additional revenues to be paid by Eveleth to MP for the difference between the old and new contract demand levels.

The Commission has not acted upon the Eveleth contract as of the time of this Order. However, the Commission must accept some projection of sales revenues from Eveleth to determine the revenue requirement in this rate case. Therefore, for the purposes of this Order, the Commission will reflect the contract demand levels in the proposed agreement. By so doing, the Commission is expressing no opinion on the appropriateness of the provisions of the new agreement.

3. Sales to Inland

The DPS proposed an upward adjustment in projected revenue to reflect Inland's forecast of its test year demand levels. Inland's projected test year demand is about 10% higher than the demand used by MP in its rate case filing. The DPS indicated that Inland recently completed plant modifications to allow production at a level which will permanently increase Inland's electric requirements. MP agreed with the DPS revised forecast of demand for Inland, but not the revenue implications, as discussed later. The Inland Group indicated that, should the Commission not adopt the Inland Group's proposed excess capacity adjustment, test year demand revenue adjustments should be made for Inland. The Commission agrees with the parties and the ALJ that test year revenues should reflect Inland's own forecast of demand, as proposed by the DPS.

4. Sales to Hibbing

The record indicates that Hibbing has made a large capital investment to permit operation at 9.1 million tons per year, rather than the 6.2 million tons in MP's forecast. Hibbing's owners have indicated their intention to produce at the higher production rate for all of 1988. The DPS proposed a revenue forecast for Hibbing which splits the difference between the two production levels. MP opposed inclusion of any revenue from excess demand sales to Hibbing Taconite, arguing that the sales are too speculative, given the 30-day cancellation provision in its approved agreement with Hibbing. The OAG argued that, if Hibbing negotiated a new excess demand agreement with MP covering sales in 1988, the higher production level should be assumed for all of the test year.

On December 30, 1987, the Commission approved a contract amendment which allows Hibbing to take power in excess of 120% of its contract demand level throughout 1988 without establishing a new permanent contract demand level. Hibbing retains the right to cancel the agreement upon 30 days notice to Minnesota Power. The Commission finds that this new agreement provides substantial evidence of Hibbing's intention to continue to operate at the higher production rate for as long as it can. Hibbing clearly has an economic incentive to do so. The Commission notes that the ninth month of the test period has started, and there has been no indication that Hibbing intends to reduce its production rate. Therefore, the Commission agrees with the arguments of the OAG and concludes that revenues from Hibbing should be calculated assuming operation for the entire test period at the 9.1 million ton production rate. The Commission notes that any drop-off of demand could be considered in the rates investigation in 1989 ordered in NSP, MP, E-002, 015/PA-86-722.

5. Calculation of Jurisdictional Revenues

MP argued that revenues from any excess demand sales should be calculated using the Company's proposed rates to reflect actual conditions when prospective rates will be in effect. The DPS argued that using proposed rates would not permit accurate determination of the revenue requirement in this proceeding and would inappropriately assume acceptance of the Company's proposed rates. The Commission agrees with the DPS and the ALJ that present rates should be used in determining excess demand revenues in this rate case for the reasons given by the DPS.

The Commission will treat the revenues from excess demand and the Eveleth buy-down as an offset to the cost of retail service, as recommended by MP. No intervenor argued that it would be inappropriate to treat the revenues in this way. However, the Commission believes this treatment may need further review in the future if Large Power excess demand becomes a major part of MP's total system load.

6. Other Adjustments

The DPS indicated that its financial adjustments for recommended changes in billing units were based upon MP's financial statements. The DPS stated that it had to modify those financial statements, because MP used proposed rates in preparing its financial statements for prospective rates. The DPS provided a schedule which converted all excess demand revenues from Minnesota Power's proposed-rates basis to the DPS present-rates basis. The schedule also accounted for additional excess energy revenue. The Commission finds the DPS method to be a reasonable way of calculating the revenue effects of the billing unit changes discussed above. The Commission will modify the calculation in accordance with decisions discussed above. The specific procedure and figures used by the Commission are shown in the table below.

	$
Firm Demand Reduction - Eveleth	(1,612,397)
Additional Demand Revenue:	
Hibbing	6,920,986
Inland	762,451
Eveleth Buy-Down ($15.80/kW/mo.)	2,899,800
Reversal of MP's 7/27/87 Filing	(481,800)
Total	10,101,437
Jurisdictional Portion (89.5%)	9,040,786
Additional Energy Revenue:	
Hibbing	432,620
Inland	221,878
Lakehead	94,653
Northwest Paper	120,885
Reversal of MP's 7/27/87 Filing	(515,500)
Total	354,536
Jurisdictional Portion (87.5%)	310,219
Net Revenue Adjustment	7,738,608

This adjustment, increasing test year revenues by $7,738,608, results in increased test year operating income of $4,622,271. In addition, the Commission finds that the reduction in firm demand due to the proposed Eveleth agreement will affect the jurisdictional allocation factors.

The Commission will not attempt to recalculate MP's cost of service. In order to reflect the inclusion of Eveleth's firm demand reduction, the Commission will estimate the allocation effects by making income statement adjustments proportional to those included in the general rate schedules attached to MP's exceptions to the findings of the ALJ. Also, the Commission will adjust rate base for the allocation effects based on its consideration of the changes shown in MP's exceptions, as well as the discussion included on page 8 of the Inland Group's exceptions. These adjustments decrease test year rate base by $298,424 and increase net operating income by $49,117.

C. Erie Contract

Since January 1980 MP has had an electric interconnection agreement with LTV Steel Mining Company, which is referred to in this proceeding by its former name, Erie. That Agreement obligated both parties to furnish one another Emergency Outage Energy and Scheduled Outage Energy to the extent of each party's standby capacity. The penalty for failing to provide this standby capacity was to be $12 per year per KW of capacity deficiency up to a maximum of $200,000 per year.

The agreement also obligated Erie to carry or make available 12 MW of spinning reserve. Should Erie be unable to provide spinning reserve, it must purchase the equivalent amount of power from MP at $2.50 per MW.

On May 11, 1982 the agreement was amended to allow economy energy sales to Erie up to its plant capacity during periods when MP's incremental price for energy was equal to or less than Erie's decremental price for energy. Since that time Erie has chosen to buy economy energy from MP rather than operate its own generating plant. During this time the Company has not collected separate contract penalties for failing to provide standby capacity or for failing to provide spinning reserve, stating that these amounts were included in Erie's economy energy payments.

There are two issues before the Commission in regard to the Erie contract. One is whether projected revenues should be adjusted to include the contract penalties the Company has not been collecting. The other is whether the economy sales themselves are improper and require corrective action by the Commission.

1. The Uncollected Contract Penalties

Eveleth and the Superwood Group recommended that test year revenues be increased by the amount of $462,800 to reflect the revenues which were not collected for spinning reserve and standby capacity under the original interconnection agreement.

MP argued that no adjustment was necessary because the charges for economy sales made to Erie included the $462,800 provided for in the interconnection agreement.

The ALJ recommended that no adjustment be made to test year revenues for the original interconnection agreement.

The Commission rejects the ALJ's recommendation that no adjustment is necessary. The record clearly shows that the Erie generator has not operated in over five years. The required standby capacity and spinning reserve have not been provided. Upon examination of the revenues included in the test year, no revenues have been identified as revenue from the Erie spinning reserve or standby capacity obligations.

The Commission rejects MP's argument that the charges for economy energy include charges for failing to provide the spinning reserve and standby capacity required by the interconnection agreement.

The Commission recognizes that the interconnection agreement establishes an operating committee to carry out the purposes of the agreement. However, it is clear from the agreement that the operating committee does not have authority to amend or modify the agreement. That committee, then, could not have waived the contract penalties at issue.

The Commission finds that the charges for the economy energy cannot be considered as satisfying the spinning reserve and standby capacity charges of the interconnection agreement. When MP chooses not to collect amounts to which it is entitled, it is the shareholders who should be responsible, not the ratepayers.

Therefore, the Commission will increase test year revenue by $462,800 ($414,206 after allocation to the Minnesota jurisdiction) to reflect the revenues which should be received from Erie in the test year under the standby capacity and spinning reserve provisions of the original interconnection agreement. This adjustment increases net operating income by $247,405.

2. The Propriety of the Economy Sales

MP has included test year revenues of approximately $13.9 million from economy sales to Erie. Eveleth recommended that the test year revenues be increased by an amount ranging from approximately $14 million to $19.5 million, depending on the billing demand assigned to Erie, on the theory that these sales should properly be billed at the Large Power rate. In addition, Eveleth argued that the economy sales must be discontinued.

The Superwood Group did not recommend imputing revenues from the economy sales at the Large Power rate. Instead, the Superwood Group recommended that Erie be given the choice of continuing the economy purchases by maintaining its plant or going on the Large Power tariff.

The ALJ recommended that no adjustment be made to test year revenues for the economy transactions.

This issue was first raised at the evidentiary hearing and largely argued in the briefs and exceptions. The Commission has not had the opportunity to review the amendments to the original interconnection agreement which initiated the economy transactions. These amendments will be reviewed at a later date. Consequently, the record is not as complete on this issue as would be ideal.

Nevertheless, an issue regarding a significant amount of revenue has been raised and must be addressed. The Commission must make a determination on the permissibility of the economy sales.

The Commission finds that Erie is in a different position than the other taconite companies. Erie has made a substantial investment in electric generating plant which it could use to supply its own power. MP's other customers have not been denied the opportunity of constructing their own generators. If the other customers had constructed their own generators, the record suggests that they would have been able to negotiate a similar rate. The fact that the availability of the rate is linked to Erie's plant capacity is further evidence of the fact that it was Erie's generating capacity alone which secured its economy rates.

The Erie economy rate is therefore not a discriminatory rate proscribed by Minn. Stat. § 216B.06 or 216B.07 (1986).

The record does not show that MP has accepted a shell of a plant as a reason to provide Erie with a competitive energy cost advantage. There is therefore nothing to be gained by forcing Erie to bring its plant on line to prove its eligibility for economy energy rates. Rather, the record indicates that MP had power available, and worked out a way to sell some of it to its advantage and to the advantage of ratepayers through economy sales to Erie. The fact that Erie also benefits does not invalidate the transaction.

The Commission finds that if Erie were forced to purchase from MP at the Large Power rate, Erie would operate its own generator instead. This would result in the elimination of the approximately $13.9 million of revenues from the economy sales. Ratepayers generally would suffer the loss of the margin on these sales and pay for it through higher rates.

The Commission finds that Erie is not receiving firm service as contended by Eveleth. The amendment agreement provides for interruptible service and provides that the supply of economy energy may be terminated at any time by either party. The fact that MP has had abundant energy supplies for the past several years and has not interrupted Erie does not convert the language of the amendment to a firm power commitment nor the service received to firm service.

The Commission concludes that it would not be in the best interest of the general body of ratepayers or in the public interest to require repricing the economy sales to Erie at the Large Power rate or any other rate. Neither will the Commission terminate the economy sales arrangement nor require additional testing of the Erie plant in this docket.

D. <u>Operation and Maintenance Benchmark</u>

The issue before the Commission is whether to adopt the Inland Group's operation and maintenance (O&M) benchmark approach in determining allowable test year O&M expenses.

The Inland Group proposed that the test year revenue requirement be reduced by $7,018,000. The Inland Group based its recommendation on its proposed O&M benchmark method of calculating allowable test year O&M expense levels. The O&M benchmark can be briefly described as a five-step process as follows:

1. Determine a base year.

2. Adjust base year for changes in MP's activities.

3. Escalate the adjusted base year by an inflation factor based on the Consumer Price Index (CPI).

4. Determine and apply a productivity improvement factor.

5. Compare the resulting benchmark amount with the test year expenses proposed by MP.

The Superwood Group originally proposed that MP be allowed to recover only the amount of O&M expenses allowed in MP's last general rate case. However, in its brief, the Superwood Group directed its attention to specific expense items included in the test year. The Superwood Group's recommendation will be discussed in the Superwood Group's budget review section of this Order.

MP argued that no adjustments were necessary to test year O&M expenses because those expenses were derived from MP's budget process, which produced an accurate reflection of the conditions likely to exist for the test year and beyond.

The ALJ did not address the Inland Group's O&M benchmark proposal.

The Commission has frequently recognized a concern about the accuracy of using a fully projected test year when setting rates. See Docket No. G-011/GR-86-144 (January 16, 1987). There, the evidence clearly suggested a history of substantial expense overstatement for test year purposes when compared to the actual expenses. As a result, the Commission reduced certain O&M and other expenses by 5% to more accurately reflect Peoples' actual historical experience.

In this case, the record contains no evidence of a consistent overstatement of test year O&M expense. Lacking such evidence, the Commission finds no reason to impose an O&M expense reduction based upon a mathematical calculation. A mathematical calculation can provide useful guidance. However, unless the evidence points to the contrary, the Commission finds that a review of the specific content and costs included in O&M expenses is preferable. This method preserves operational flexibility for the utility management. At the same time, the process of the parties' review of the specific costs included in the O&M expenses provides a reasonable procedure for assuring that rates are just and reasonable. Review of specific costs also assures ratepayers that rates are based on costs which are prudent and necessary in the provision of services in MP's service area.

The Inland Group stated that from 1981-1986, MP's power production and delivery expenses increased at less than 2% per year. The Inland Group stated that MP's non-power production and delivery expenses have increased 8% per year, indicating that the administrative and general (A&G)

expenses have not been adequately controlled.

The Commission notes that there is considerable controversy between the Inland Group and MP as to how to measure the proper percentage changes in certain expense categories. When viewing the changes on an overall basis, the Commission finds that the increase in O&M expenses (excluding fuel and purchased power) increased an average of 3.67% over the period at issue, an amount less than the 3.81% change in the CPI.

The Commission finds that MP has gone through a period of transition. The record shows that MP has moved from a construction phase to a service phase, having expanded its service centers in its service area. This resulted in an increase in A&G labor expense and a decrease in construction labor expense. Further, maintenance expenses increased due to the expanded service centers.

The Commission also finds that direct comparisons with O&M expense levels between the test year and prior years is difficult in this proceeding because of MP's cost-cutting efforts in recent years. As part of these efforts, some necessary costs were avoided or deferred to the future.

Based on the above findings, the Commission concludes that the record does not support the implementation of the O&M benchmark methodology in this proceeding. Instead, the Commission will address various individual expense issues raised by the parties in other sections of this Order.

E. Superwood Group Budget Review

The Superwood Group proposed thirty-eight individual adjustments to the Company's budgeted test year operation and maintenance (O&M) expenses. The Superwood Group argued that some expenses should be excluded entirely as non-utility, that other expenses should be allocated between utility and non-utility operations, and that some expenses should be capitalized. The adjustments proposed by the Superwood Group would reduce test year O&M expenses by $1,659,904.

In its reply brief, MP agreed that two of the contested expense items should be excluded because they are lobbying expense and that twenty-nine of the contested expense items should be allocated between utility and non-utility operations. In separating the budgeted expense items between utility and non-utility business, MP accepted the Superwood Group's non-utility allocator of 35.8% based on the total of non-utility assets divided by total consolidated assets. The adjustments accepted by MP in its reply brief would reduce test year O&M expenses by $545,669.

The ALJ's recommended findings on the contested expense items would reduce test year O&M expenses by $1,325,881.

As discussed below, the Commission finds that $1,400,377 should be removed from test year operating expenses and that test year net operating income should be increased by $836,445. The contested expense items are discussed below in three groups: those expense items that the Commission excluded totally from operating expenses; those the Commission included in operating expenses; and those the Commission generally allocated between utility and non-utility operations using the 35.8% allocator discussed above.

The amounts discussed below are total Company amounts. A jurisdictional allocation factor of approximately 89.5% must be applied to the amounts excluded from operating expense in the following discussions. The Company's position described below reflects its final position as indicated in its reply brief.

1. Items Excluded From Operating Expenses

a. Christmas Lighting Contest

MP allocated this expense between utility and non-utility, reducing operating expenses by $3,580. The Superwood Group and the ALJ excluded the total $10,000 expense on grounds that its primary purpose and effect was to promote goodwill.

The Commission agrees with the Superwood Group and the ALJ. It will disallow the entire expense on grounds that it does not qualify as a charitable contribution under Minn. Stat. § 216B.16, subd. 9(1986), but is instead an advertising expense designed primarily to promote goodwill and improve the Company's image. It must therefore be excluded under Minn. Stat. § 216B.16, subd. 8 (d) (1986).

b. Special Legislative Project

MP agreed with the Superwood Group, OAG, and the ALJ to exclude this $2,385 lobbying expense. The Commission agrees that this expense should be excluded as not reasonably necessary to the provision of utility services.

c. Holiday Decorations

MP allocated this expense between utility and non-utility, reducing operating expenses by $3,709. The Superwood Group advocated excluding the total expense of $10,359 because its primary purpose was to promote company goodwill. The ALJ allowed 50% of this expense as a charitable contribution under Minn. Stat. § 216B.16, subd. 9 (1986).

The Commission agrees with the Superwood Group that the primary purpose and effect of this expenditure was to promote goodwill and improve the corporate image. It is therefore an excluded advertising expense under Minn. Stat. § 216B.16, subd. 8 (1986), not a charitable contribution.

d. Mesabi Metal

MP included a $54,502 budget item for research on potential technologies for converting taconite to low carbon steel. The Superwood Group excluded the entire amount as a non-utility expense. The ALJ allocated this expense between utility and non-utility, excluding $19,512.

The Commission agrees with the Superwood Group that the record does not contain enough information to support this expense as reasonable or as reasonably necessary to the provision of utility services. The Commission will disallow the entire amount.

e. Baukol-Noonan Coal Option

MP included a lease option payment of $174,996 in operating expenses. The Superwood Group and the ALJ excluded the entire amount on grounds that it should be capitalized and expensed as the coal is used.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire expense. The Uniform System of Accounts, adopted by the Commission in Minn. Rules, part 7825.0300, generally prohibits including in current operating costs any expenditure not used in providing current service. There is nothing in the record to support different treatment for this expenditure.

f. North Dakota Lignite Leasing Costs

MP included an annual coal field lease payment of $26,000 in operating expenses. The Superwood Group advocated excluding the entire expense on grounds that it should be capitalized and expensed as the coal is used. The ALJ included the $26,000 in operating expenses.

The Commission agrees with the Superwood Group and will exclude the entire expense for the same reasons given in regard to the Baukol-Noonan Coal Option.

g. Reid and Priest

MP allocated legal fees to utility and non-utility and excluded $19,332 from operating expenses. The Superwood Group excluded the entire $54,000 on grounds that it related to non-utility operations. The ALJ agreed with MP's position.

The Commission agrees with the Superwood Group and will exclude the entire expense on ground that there is not enough information in the record to support a conclusion that the expense is utility-related, is reasonable, and is reasonably necessary to the provision of utility services.

h. Interest and Dividends

MP allocated preparation and mailing of 1099s to utility and non-utility and excluded $4,743 from operating expenses. The Superwood Group and the ALJ excluded the entire cost of $13,249 because this is a shareholder expense.

The Commission agrees with the Superwood Group and the ALJ and will reduce operating expenses by $13,249 on grounds that this is a shareholder expense.

i. Minnesota Business Partnership

MP allocated this planning expense to utility and non-utility, excluding $1,701 from operating expenses. The Superwood Group and the ALJ excluded the entire expense of $4,750 because it is for lobbying expenses.

The Commission agrees with the Superwood Group and the ALJ and will reduce operating expenses by $4,750 on grounds that this is a lobbying expense not reasonably necessary to the provision of utility services.

j. Medical Plan Expense

MP allocated life insurance for the Topeka Group to utility and non-utility and excluded $1,611 of test year operating expenses. The Superwood Group and the ALJ excluded the entire expense of $4,500 because it is for non-utility employees.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire expense as non-utility.

k. Agency Services

MP allocated agency services between utility and non-utility and excluded $18,616 of operating expenses. The Superwood Group and the ALJ excluded the entire $52,000 expense because it primarily benefitted shareholders by improving the corporate image.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire expense because its primary purpose and effect was to improve the corporate image.

l. Legislative Presentations

MP agreed with the Superwood Group and the ALJ to exclude $1,600 of lobbying expenses from test year operating expenses.

The Commission agrees with the Superwood Group, ALJ, and MP and will exclude the expense as not reasonably necessary to the provision of utility services.

m. Financial Communications

MP allocated communications expenditures to both utility and non-utility and excluded $12,172 of expense from operating expenses. The Superwood Group and the ALJ excluded the entire amount as a shareholder expense.

The Commission agrees with the Superwood Group and the ALJ that communications to investors should be charged to the shareholders.

n. American Bank Note Company

MP allocated the cost of printing stock certificates to the utility and non-utility and excluded $3,580 of test year operating expenses. The Superwood Group and the ALJ excluded the entire $10,000 cost because it is a shareholder expense.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire amount because it is a shareholder expense.

o. Miscellaneous Consultant Services

MP allocated consulting expenses between utility and non-utility and excluded $17,900 of operating expenses. The Superwood Group and the ALJ excluded the entire $50,000 of expense because there is not enough evidence in the record to support this as a utility expense.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire expense due to lack of documentation that the expense is utility-related, is reasonable, and is reasonably necessary to the provision of utility services.

p. Northeastern Minnesota Development Association

MP allocated dues expense to utility and non-utility and excluded $7,160 of expense from test year operating expenses. The Superwood Group and the ALJ excluded the entire amount of $20,000 because there is not enough evidence in the record to support this as a utility expense.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire expense because the record does not support the conclusion that it is utility-related, that it is reasonable, or that it is reasonably necessary to the provision of utility services.

q. Legal Services

MP allocated legal services to protect company management to utility and non-utility and excluded $5,728 of expense from operating expenses. The Superwood Group and the ALJ excluded the entire amount of $16,000 because these fees relate only to management's protection from personal liability.

The Commission agrees with the Superwood Group and the ALJ and will reduce operating expenses by $16,000 because of lack of evidence in the record to support this expense as utility-related, as reasonable, and as reasonably necessary to the provision of utility services.

r. Financial Mailing Lists

MP allocated the cost of mailing information to the financial community as a utility and non-utility expense and excluded $6,387 of expense from the test year. The Superwood Group and the ALJ excluded the entire expense of $17,840 because it primarily benefits shareholders.

The Commission agrees with the Superwood Group and the ALJ and will exclude the entire amount because it is a shareholder expense.

s. 1935 Act Amendment

MP allocated the cost of monitoring changes in the Public Utility Act of 1935 to utility and non-utility and excluded $1,790 of test year expenses. The Superwood Group advocated excluding the entire expense of $5,000 because these costs are lobbying expenses, not ratepayer costs. The ALJ agreed with MP and allocated this expense to both utility and non-utility.

The Commission agrees with the Superwood Group and will exclude the entire expense on grounds that it primarily benefits shareholders and is not reasonably necessary to the provision of utility services.

t. Boswell Thermo Energy Utilization

MP included $3,600 in operating expenses for an experimental program for raising game fish. The Superwood Group advocated excluding the entire amount as an expense related to non-utility activities. The ALJ excluded $1,289 from expenses for the non-utility portion because this expense benefits both utility and non-utility.

The Commission agrees with the Superwood Group and will exclude the entire expense as not reasonably necessary to the provision of utility services.

2. Expenses Included In Operating Expenses

a. Hibbard Generation Planning Study

MP included $8,002 in expenses for a study on reutilization of the Hibbard Units. The Superwood Group excluded this expense from operating expenses because it should be capitalized and amortized when the units are reactivated. The ALJ included the $8,002 of expense in the test year because it is utility related.

The Commission agrees with the ALJ and MP and will include the $8,002 in operating expenses. The Commission finds that the study is necessary to the provision of utility services, since the Company anticipates the need to reactivate the Hibbard plant after the sale of capacity from Boswell 4 and Coyote. The Commission also finds this cost more in the nature of an operating expense than a capital improvement.

3. Expenses Allocated to Utility and Non-Utility

a. Strategic Planning Process

MP allocated $6,001 of this $16,763 expense to non-utility. The Superwood Group advocated excluding the entire expense because it related to nonregulated activities. The ALJ agreed with MP and allocated the expense between utility and non-utility, saying it benefitted both.

The Commission agrees with the ALJ and MP and will allocate the expense. The Commission finds that strategic planning is a useful tool for prudent and effective corporate management and benefits ratepayers as well as shareholders.

b. <u>Coal Fuel Cost Dynamics</u>

MP included costs of $9,115 for research to lower fuel costs through cartel purchasing. The Superwood Group excluded the entire expense since it was for an unregulated activity. The ALJ excluded $3,263 of $9,115 because the expense benefits both utility and non-utility operations.

The Commission agrees with the ALJ and will allocate the expense. The Commission finds that reducing fuel costs would benefit ratepayers and that the utility portion of the expense is therefore reasonable and reasonably necessary to the provision of utility services.

c. <u>Rating Agency Appraisal</u>

MP allocated $13,318 of $37,200 to non-utility expense for appraisal fees that support both utility and non-utility operations. The Superwood Group advocated excluding the entire amount because of lack of evidence in the record. The ALJ agreed with MP and allocated the expense between utility and non-utility operations.

The Commission agrees with the ALJ and MP and will allocate the expense as benefitting both utility and non-utility operations. Rating agency services are integral to the financing of the Company and are therefore reasonably necessary to the provision of utility services.

d. <u>Emerging Trends Anlysis</u>

MP allocated $6,855 of $19,146 to non-utility expense for a program to keep MP informed of changes in the business environment. The Superwood Group excluded the entire expense on grounds that the program is directed at MP's nonregulated business. The ALJ agreed with MP and allocated $6,855 of this expense to the non-utility operations.

The Commission agrees with the ALJ and MP and will allocate the expense as benefitting both utility and non-utility operations. Knowledge of the business environment is essential to the prudent management of the Company, and this expense is therefore reasonably necessary to the provision of utility services.

e. <u>1987 Annual Report</u>

MP allocated $39,774 of $111,100 to non-utility expenses for the annual report required by the SEC. The Superwood Group agreed with MP to allocate the expense between utility and non-utility since Minn. Stat. § 216B.16, subd. 8 (1986) allows recovery of expenses incurred by the utility to provide information about corporate affairs to its owners. The ALJ excluded the entire amount as a shareholder expense.

The Commission agrees with the Superwood Group and MP and will reduce operating expenses by $39,774 for the non-utility portion of the expense. The utility portion of the expense is allowable under Minn. Stat. § 216B.16, subd. 8 (1986).

f. General Office/Lake Superior Plaza

MP allocated $148,582 of $594,329 of maintenance costs for the office building and parking ramps to non-utility operations. The Superwood Group and the ALJ agreed. The 25% allocation factor used was based on the allocation of the building lease between utility and non-utility activities.

The Commission agrees with the parties and will use the 25% allocator as a fair and reasonable measure for assigning maintenance costs of this facility to non-utility operations.

g. Stock Exchange Fees

MP excluded $9,929 out of $27,735 for non-utility expense for annual fees for listing stock on the stock exchange. The Superwood Group and the ALJ excluded all of the $27,735 on grounds that this is essentially a shareholder expense.

The Commission agrees with MP and will allow the allocated portion of the expense on grounds that listing services are essential to the financing of the Company and therefore necessary for the provision of utility services.

h. SEC Form 10K & 10Q

MP allocated $9,684 out of $27,050 to non-utility operations for annual reports required by the Securities and Exchange Commission (SEC). The Superwood Group excluded the entire $27,050 because MP is not required to be a publicly held corporation subject to SEC jurisdiction. The ALJ agreed with MP and allocated the expense as benefitting both utility and non-utility operations.

The Commission agrees with MP and the ALJ and will allow the allocated expense as essential to the financing of the Company.

i. Employee Cafeteria

MP allocated $1,009 of $24,600 in employee cafeteria expenses to non-utility operations. This figure was derived by multiplying total expenses by the percentage of non-utility employees in the building. The Superwood Group and the ALJ allocated the expense on the basis of the cafeteria's square footage, using the 25% allocator applied to the lease for the building as a whole.

The Commission agrees with the Superwood Group and the ALJ and will allocate the expense on the basis of square footage, using the allocator applied to the building as a whole. The Commission is not persuaded that cafeteria space is different enough from the space in the rest of the building to justify a different allocator.

j. Registrar and Transfer Agent Expenses

MP allocated $12,530 of $35,000 to non-utility operations for expenses related to stock transfers. The Superwood Group and the ALJ excluded the entire expense as shareholder expenses.

The Commission finds that the expense is reasonably necessary for the financing of the Company but that $12,530 should be allocated to non-utility operations.

k. Meetings With Rating Agencies & Institutional Investors

MP allocated $3,491 of $9,750 for expenses associated with meeting with rating agencies and institutional investors. The Superwood Group excluded the entire expense as a shareholder expense. The ALJ agreed with MP and allocated the expense as benefitting both utility and non-utility operations.

The Commission agrees with MP and the ALJ and will allocate the expense as integral to the financing of the Company.

l. Board of Directors Fees

MP agreed with Superwood to allocate $79,655 of $222,500 in Board of Directors fees to non-utility operations. The ALJ agreed with the Superwood Group and MP.

The Commission agrees with the parties and will allocate the expense as benefitting both utility and non-utility operations.

m. Bond Trustee Expense

MP agreed with the Superwood Group to allocate $54,774 of $153,000 in administrative costs to non-utility operations. The ALJ agreed with both parties.

The Commission agrees with the parties and will allocate the expense as benefitting both utility and non-utility operations.

n. Audit Fees

MP agreed with the Superwood Group to allocate $56,743 of $158,000 in audit expenses to non-utility operations. The ALJ agreed. The Commission finds this reasonable and will allocate the expense as benefitting both utility and non-utility operations.

o. Shareholder Communications

MP originally proposed to include all shareholder communication expenses in the test year income statement. In its reply brief, MP proposed to allocate $9,487 to non-utility activities. The Superwood Group originally proposed to eliminate the entire amount in this category, but agreed with MP's proposal to allocate at oral argument.

The ALJ recommended that the total amount be excluded as a shareholder expense.

The Commission agrees with MP and the Superwood Group that test year expense should be reduced by $9,487 to reflect the allocation of a portion of these expenses to the non-utility activities of MP. The Commission finds that Minn. Stat. § 216B.16, subd. 8 (1986) prevents a total disallowance of this expense incurred to disseminate information about the corporate affairs to the Company's owners.

p. Annual Shareholder Meeting and Shareholder Notices

Originally, MP proposed to include the full amount of these costs as test year expense. The Superwood Group initially recommended a full exclusion of these costs. Finally, MP proposed to allocate $42,880 to non-utility activities. At oral argument, the Superwood Group agreed with MP's proposal to allocate a portion to non-utility activities.

The ALJ recommended a full exclusion of these expenses as shareholder-related expenses.

The Commission agrees with MP and the Superwood Group that $42,880 should be allocated to non-utility activities. The Commission recognizes that it is unlikely that only utility information is discussed at the annual meeting. The Commission finds that Minn. Stat. § 216B.16, subd. 8 (1986) prevents the total disallowance of this expense incurred to disseminate information about the corporate affairs to the Company's owners.

q. Vegetation Control

The Superwood Group raised concerns regarding vegetation control expenses, stating that the projected test year expense was substantially higher than the actual 1986 amount. The Superwood Group indicated that the actual amount for 1986 was $809,500, yet the Company included $2,081,592 in test year expense. The Superwood Group recommended that an average amount of $1,585,133, averaging the 1986 actual and the amounts projected for the years 1987 and 1988, be used as the test year expense.

MP argued that 1986 is not representative of the costs that will be incurred in the future and that the Company's proposed amount is the normal amount for one year.

The ALJ recommended that the vegetation control expenses be reduced as proposed by the Superwood Group.

The Commission agrees with the ALJ and the Superwood Group. The record clearly shows that significant vegetation control work was delayed in 1986 in an effort to reduce expenses. The Company has not convinced the Commission that the amounts projected for the test year have not been skewed by the reduction in vegetation control in the previous year. (See Superwood Exhibit 111.) Therefore, the Commission will reduce test year expenses by $496,459 as proposed by the Superwood Group.

F. Laskin Operation and Maintenance Expense

The Commission must decide whether to exclude the Laskin O&M expenses from the test year income statement.

The Inland Group recommended adjustments to its proposed O&M benchmark methodology to specifically exclude the Laskin O&M expenses if the Commission did not adjust for excess capacity as recommended. They also recommended excluding the Laskin O&M expenses if the Commission did not adopt the O&M benchmark methodology.

The Superwood Group recommended that the Laskin O&M be excluded from the test year income statement if the Commission did not accept its excess capacity recommendations. The Superwood Group's recommendation would reduce test year expenses by $2,611,240, including depreciation expense on the Laskin station.

The ALJ recommended that the Laskin O&M expenses be included in test year expenses.

The Commission recognizes that the Laskin O&M expenses were excluded in MP's last general rate case. However, depreciation expenses were allowed. The Commission finds that circumstances are different in the present case. In the last case, the Commission made no adjustment for excess capacity. In this case, as discussed in the excess capacity section of this Order, the Commission has already made an adjustment for MP's excess capacity situation. The Commission finds that making an adjustment for the Laskin O&M would duplicate its adjustment on the excess capacity issue.

The Commission accepts the ALJ's recommendation that Laskin O&M expenses be allowed as test year expenses. The Laskin station has generated in excess of 60,000 MWH hours in 1987, and is expected to be operated throughout the test year. As a result of the Boswell 4 and Square Butte sale, the Laskin station is projected to play an even larger role in MP's system.

Based on the above findings, the Commission will not adjust the test year income statement to exclude the Laskin O&M expenses.

G. Mine Closing Costs

The issue before the Commission is whether to allow MP to begin funding a sinking fund through the automatic fuel adjustment clause in order to meet expected post-shipment closing costs of a Montana coal mine.

MP proposed to increase test year fuel expense by $1,496,165 to fund a sinking fund. The purpose of the sinking fund is to have funds available for the closing of the Big Sky mine in Montana in 1990.

The DPS recommended the exclusion of the post-shipment closing costs due to the many uncertainties surrounding the amounts and the timing of the proposed expenditures.

The Inland Group (supported by Eveleth) recommended the exclusion of the post-shipment mine closing costs for the same reasons. The Inland Group recommended that the issue be further investigated in a separate proceeding.

The ALJ recommended the adoption of the recommendations of the Inland Group.

MP's 25-year contract for coal from the Big Sky coal mine in Montana obligates MP to pay reclamation costs required by a statute enacted during the contract term, the Surface Mining Control and Reclamation Act. MP estimated the costs of the mine closing to be approximately $9.4 million, and proposed a sinking fund intended to fund the total cost by 1993. MP proposed that the sinking fund would earn interest at the after-tax cost of capital determined in this proceeding. Funding was proposed as a fuel-related cost passed through the fuel adjustment clause.

The Commission agrees with the parties that there are many uncertainties surrounding this issue. The record contains several alternative final closing cost projections, ranging from as low as $6.3 million to as high as $18.3 million.

The uncertainties surrounding this issue include such questions as: Will MP terminate the contract? Will pit B actually be opened? Should a portion of the estimated costs be assessed to others that have purchased coal from this mine? What happens to the excess funds if the sinking fund is overfunded? Why fund the entire amount by 1993 when the final payments may not be made until 2000 or beyond? How will the tax deferrals be treated? Is it appropriate to allow MP to collect the total amount of closing costs beginning now, when the costs have been known to some extent beginning since 1977? Is it appropriate to include these costs in the fuel adjustment clause as proposed by MP? Is an internal sinking fund appropriate?

Despite the many uncertainties, the Commission recognizes that some amount of mine reclamation costs is inevitable. The Commission finds that such costs are necessary for the provision of electric service. No party has indicated that ratepayers should not be required to pay those costs. Recognizing that mine reclamation costs are a cost of providing electric service, the Commission is greatly concerned that those costs be paid by those who benefitted from the coal mined. The Commission finds that delaying the start of some form of cost recovery until this matter can be further reviewed in a separate proceeding is even more likely to cause future users to pay for past benefits. This must be avoided as much as possible.

Therefore, the Commission will allow some collection for mine closing costs to begin in this proceeding. The Commission will authorize MP to include $640,000 as test year expense for post-shipment mine closing costs. This figure was derived using the record figure of $4,800,000 as an estimated total cost of closing pit A. Applying the 7.69% after-tax cost of capital calculated in this proceeding and a six-year recovery period, an annual revenue stream of $640,000 was calculated. Due to the uncertainty regarding the tax deferral treatment, the Commission will treat this amount as any other expense included in the test year income statement.

The Commission is not presently allowing this item as an automatic fuel adjustment. Further factual development and analysis regarding its proper treatment is necessary. To facilitate this, the Commission will require MP to file updated and detailed information addressing the concerns identified by the parties and the Commission within two years of the date of this Order.

In making this adjustment, the Commission will remove the $1,519,000 of revenue (apparently included as a present revenue although it was a proposed revenue), $1,496,165 of fuel expense, and $9,195 of tax expense included by MP in its filing. After reversing MP's proposed adjustment, the Commission will increase test year expense for mine closing by $640,000. The combined effect of the Commission's adjustment will reduce test year net income by $395,911 after taxes.

H. Research Expenses

The Commission must determine the amount, if any, of the Company's Electric Power Research Institute (EPRI) dues to allow as a test year expense. MP included its full dues of $1,272,666. The DPS recommended that the total amount be disallowed on grounds that the expense was not essential to the operation of the utility. The DPS pointed to the fact that MP had discontinued its EPRI membership in 1986 and early 1987 as evidence of its superfluous character.

The OAG recommended that the portion of EPRI dues attributable to nuclear research, $237,989, be disallowed. The OAG argued that, since MP has no nuclear facilities, its ratepayers receive no benefit from this expenditure.

The ALJ recommended the disallowance of that portion of the EPRI dues attributable to nuclear research. The Commission agrees with the ALJ on this issue.

A total disallowance of EPRI dues would not be justified. The record supports MP's argument that it ceased paying EPRI dues in 1986 due to a dispute over the billing formula, not because it questioned the value of membership. The decision may also have been influenced in part by the Company's low earnings on electric sales during that period. In any case, the record supports the Company's contention that its withdrawal was never intended to be anything other than temporary. The Commission finds that these facts do not show that the EPRI membership is viewed as expendable by the Company. Furthermore, the Commission believes that professional affiliations such as EPRI generally benefit the ratepayer by informing the utility of improved methods for the delivery of utility services.

The Commission also agrees with the ALJ that the portion of EPRI dues related to nuclear research should be excluded from the test year expenses. MP has no nuclear capacity. MP's purchases from MAPP, where some nuclear generation exists, are limited. MP has not identified nuclear research projects which have been applied by MP in its fossil fuel system. The Commission finds that the benefits to Minnesota ratepayers of the portion of EPRI dues related to nuclear research are minuscule in relation to the amount expended. Further, MP's argument that it cannot avoid the nuclear research contribution once it chooses to join EPRI does not justify allowing a test year expense which provides little or no benefit to the ratepayers.

As in the recent rate case, Interstate Power Company, Docket No. E-001/GR-86-384 (May 1, 1987), the Commission will disallow the portion of EPRI dues related to nuclear research. This action reduces test year expense by $237,989 and increases test year net operating income by $142,151 after tax effects.

While the Commission rejected the DPS arguments that MP's actions showed that the EPRI costs were not necessary, the Commission is concerned that the EPRI dues will frequently become a target when management decides to cut costs. The Commission recognizes that such management discretion can be abused to the detriment of ratepayers. In order to protect against such abuse, the Commission will instruct the parties to verify in each of the investigations ordered in NSP, MP, E-002, 015/PA-86-722 that MP is indeed paying the EPRI dues.

I. Edison Electric Institute (EEI) Dues

MP included in test year expenses full EEI dues, including $1,600 for lobbying activities, $58,875 for institutional advertising, and a $47,887 contribution to the Three Mile Island clean up. MP conceded that the amounts related to lobbying activities and institutional advertising should be removed. MP contended that the portion allocated for Three Mile Island clean up should be allowed on grounds that the clean up benefitted ratepayers by safeguarding public confidence in the utility industry.

The OAG recommended that all three items totaling $108,362 be excluded from test year expenses.

The ALJ agreed with the OAG.

The Commission accepts the ALJ's recommendation. The Commission finds that lobbying activities are inappropriate test year expenses because they do not add to the quality of electric service. Further, allowing lobbying costs may impose costs ratepayers to support political positions contrary to their convictions or best interests. As in NSP, E-002/GR-85-558, the Commission will disallow the portion of EEI dues related to lobbying activities.

The Commission agrees with the ALJ that the portion of EEI dues related to institutional advertising must be excluded. Minn. Stat. § 216B.16, subd. 8(d) (1986) precludes the recovery of expenses related to this form of advertising.

The Commission agrees with the ALJ that the expenses related to the clean up of Three Mile Island should be disallowed as well. MP's reliance on nuclear power is too insignificant to support arguments that there may be spill-over benefits to ratepayers received from the contributions to the clean up. MP's arguments that a failure of a timely clean up of the Three Mile Island situation adds to the risk of the entire industry, thereby decreasing investor confidence, was not supported by MP's rate of return witness Benderly. Mr. Benderly indicated that there had been no demonstrated added risk to a utility owning a nuclear plant for quite some time. Further, MP has no legal obligation to contribute to the clean up of Three Mile Island.

Therefore, the Commission will exclude all three items from test year expense. This adjustment decreases test year expense by $108,362 and increases test year net operating income by $64,725 after tax effects.

J. Newsletter Expense

The Commission must determine whether it is appropriate to include expenses related to the "Energizer" newsletter in test year expense.

MP included $16,088 for expenses related to its "Energizer" newsletter. MP argued that the newsletter is at least 50% related to conservation, safety, and customer education.

The DPS recommended that the entire amount be disallowed.

The ALJ recommended the DPS position be adopted.

The Commission agrees with the DPS. After reviewing the copies of the "Energizer" included in the record, the Commission finds that the primary design of the newsletter is to promote goodwill and to improve MP's public image. The inclusion of a few conservation and safety articles does not change that primary purpose. The Commission concludes that the newsletter expenses must be disallowed as advertising designed to promote goodwill or improve the public image. Minn. Stat. § 216B.16, subd. 8(d) (1986).

This adjustment reduces test year expense by $16,088 and increases net operating income by $9,609 after tax effects.

K. Marketing Expense

The issue before the Commission is whether MP should be allowed to recover the expenses associated with its commercial and residential marketing programs.

MP included $113,770 of costs for its residential marketing program. The residential program includes: 1) Existing space heating, 2) New construction space heating, 3) Existing water heating, and, 4) New construction water heating.

MP also included $389,978 for its commercial marketing program. The commercial program includes: 1) Supplemental space heat, 2) New construction space heat, 3) Existing water heater, 4) New construction water heater, 5) Lighting, 6) Cooking, and, 7) Other.

The DPS recommended that all of the costs for the residential marketing programs and two-sevenths of the costs for the commercial program be disallowed.

The ALJ recommended the DPS position.

The Commission adopts the position of the DPS. As in NSP, E-002/GR-85-558, the Commission finds that before marketing expenses can be included in rates, a quantitative cost-benefit must be demonstrated.

The Commission rejects MP's argument that it is sufficient if the total marketing effort is cost-effective and that it is not necessary to evaluate each marketing program individually. The Commission finds that disallowing individual non-cost-effective programs results in a larger overall positive net present benefit value for ratepayers. MP should not devote ratepayers' resources to marketing programs which are not cost-effective. Benefits from cost-effective programs should not be consumed by non-cost-effective programs.

The Commission finds that all of the residential marketing programs and two of the commercial marketing programs (new construction space heat and supplemental space heat) are not presently cost-effective. Some will not be cost-effective until the year 2000. The associated costs for these programs will be excluded.

This adjustment reduces test year expense by $225,192 and increases net operating income by $134,507 after tax effects.

L. Dual Fuel Advertising

The Commission must determine whether the expense for dual fuel advertising is appropriate to include as a test year expense.

MP included $96,000 in its "advertising expense" account. This amount was identified as conservation advertising in MP Exhibit 30.

The DPS and the OAG recommended that the advertising expenses related to dual fuel be disallowed in this proceeding.

The ALJ recommended that the advertising expenses for the dual fuel program be disallowed.

The Commission adopts the DPS position regarding the dual fuel advertising. The Commission has reviewed copies of the dual fuel advertising and finds that the ads are primarily designed to promote the consumption of electricity. The advertising is not designed primarily to encourage conservation through the use of dual fuel. Further, MP's witness testified that the advertising is not intended to reach those customers already heating electrically. Rather, it is used to reach users of other heat sources and to suggest electricity as a supplement to their systems.

Minn. Stat. § 216B.16, subd. 8(c) (1986) prohibits a utility from recovering expenses for advertising which is primarily designed to promote the consumption of the utility's product. The Commission finds that this advertising is primarily designed to promote the consumption of electricity and must be disallowed under the statute.

This adjustment reduces advertising expense by $96,000 and increases net operating income by $57,341.

M. Advertising Expense

MP included $235,880 of advertising expense in the account titled "sales expense" for marketing-related advertising activities. This account is separate from the "advertising account" discussed in the dual fuel advertising section of this Order.

The DPS recommended that the entire amount be excluded. The ALJ agreed.

The Commission recognizes MP's concern that disallowing the entire $235,880 here and the $96,000 of dual fuel advertising in the previous section might result in a double exclusion of the dual fuel expense. The Commission has reviewed the record on this question, however, and finds that the supporting schedules clearly show that the $96,000 of dual fuel advertising expense was included in the "advertising expense" account and was therefore properly excluded there.

The Commission also finds that the testimony of MP's witness, Mr. Harmon, clearly indicates that $96,000 in dual fuel advertising expense is also included in the "sales expense" account being examined here. Mr. Harmon stated that it was not appropriate to allocate dual fuel advertising to the wholesale jurisdiction. It should therefore be excluded again.

The Commission accepts the recommendations of the DPS. The Commission finds that the marketing-related advertising expenses are similar to the dual fuel advertising expenses in that they are incurred to promote electric sales. Therefore, the $235,880 of advertising expense must be disallowed as promoting consumption of electricity. Minn. Stat. § 216B.16, subd. 8(c) (1986).

In addition, the advertising expenses included here contain expenses related to the residential and commercial marketing programs discussed earlier in this Order. Those programs were not found to be cost-effective. As in NSP, E-002/GR-85-558, and in OTP, E-017/GR-86-380, the Commission finds that advertising expenditures associated with marketing programs that are not cost-effective must also be excluded.

For the reasons discussed above, the Commission will exclude the $235,880 of advertising expense included in the "sales expense" account. This adjustment reduces test year expense by $235,880 and increases test year net operating income by $140,891.

N. Interest Synchronization

The issue for the Commission to decide is whether the interest expense deduction for tax purposes should be the projected actual interest expense or should be calculated by multiplying the rate base times the weighted cost of debt (interest synchronization).

MP proposed the interest synchronization method of calculating the interest expense deduction for tax purposes. MP's proposal increased test year income tax expense by approximately $2,755,563 over the result obtained by using its projected actual test year interest expense.

The OAG initially recommended that interest synchronization not be allowed in this case because

MP is not including the ITCs in its rate base. In its briefs and exceptions to the ALJ, the OAG recommended three solutions which would correct MP's alleged misallocation of its low cost debt to shareholders for use in MP's non-utility security investment portfolio. Those proposed solutions included: 1) Reallocate the lowest cost debt to match the utility rate base; 2) Include the assets and income of the security investment portfolio in the ratemaking process; or 3) Use actual projected interest expense rather than interest synchronization.

The DPS did not specifically address this issue, but did include the effects of interest synchronization in its proposed rate base adjustments.

The ALJ stated that the interest synchronization method is appropriate for calculating the interest expense deduction.

The Commission will address the interest synchronization issue at this time. The OAG's proposals to reallocate debt and to include the security investment portfolio in the ratemaking process will be discussed in the rate of return section of this Order.

Without accepting all of the ALJ's reasoning, the Commission finds that the interest synchronization method is appropriate for calculating the interest expense deduction for tax purposes in this proceeding.

The OAG argued that MP allocated some of the low-cost pollution control bonds, zero-cost unamortized ITCs, and other low-cost debt to fund its non-utility security investment portfolio. As a result, the OAG argued that the cost of capital to the ratepayers was increased by $2.6 million. The Commission finds that this argument is more appropriately addressed in the rate of return section of this Order and will be discussed there. It is not appropriate to mix the interest synchronization issue with a cost of capital issue. Interest synchronization merely takes the weighted cost of debt determined in the rate of return portion of this proceeding and multiplies it times the rate base. Concerns about the appropriate cost of capital and the appropriate cost of debt are more properly considered in the context of rate of return and related issues.

The Commission accepts the ALJ's and MP's argument that the use of interest synchronization properly matches the interest expense deduction for tax purposes with the interest expense paid by the ratepayer through the rate of return. Further, by applying the weighted cost of debt to the rate base determined in this proceeding without reducing it for the amount of unamortized ITCs, the ratepayer receives the benefit of an interest deduction for that part of rate base financed by the ITCs. The Commission finds that this properly shares the benefits of the ITCs with the ratepayers to the maximum extent permitted by law, as found by the Commission in <u>NSP</u>, E-002/GR-85-558 at 49.

Further, MP's projected actual interest expense includes the interest expense on debt which is not used for financing the utility rate base. To allow the ratepayer the benefit of the actual interest expense would allow the ratepayer to share in an interest deduction for tax purposes which greatly exceeds the amount of interest expense paid by the ratepayer through the rate of return. The Commission finds that this does not meet the regulatory goals of economy and fairness to ratepayers and allowing the utility to recover its actual reasonable operating costs.

Disallowing the use of interest synchronization in this proceeding would be inconsistent with precedent established in several recent rate cases beginning with NSP, E-002/GR-85-558 and including OTP, E-017/GR-86-380, NSP, G-002/GR-86-160 and Interstate, E-001/GR-86-384. Arguments have been made that the capital base was usually less than the rate base in the general rate cases where interest synchronization has been allowed. The Commission notes that in each of the cases listed, the capital base exceeded the jurisdictional rate base. The Commission finds that no arguments raised here are sufficiently compelling to warrant the Commission's departure from that precedent.

In applying interest synchronization, the Commission will multiply the Commission determined rate base (after removing the estimated cash working capital effect for interest synchronization included in the supplemental filing and before adjustments for the cash working capital effect of interest synchronization and the rate decrease) of $543,185,499 by the 4.13% weighted cost of debt approved by the Commission. After iterations, this calculation produces an interest deduction of $22,432,098 (compared to the $29,604,259 projected actual amount) to be used for state and federal income tax purposes.

Consistent with prior Commission decisions, the Commission will also adjust income tax expense for the tax effects resulting from the change in cash working capital related to the rate decrease ordered. The combined effect of these calculations increases state and federal income tax expense by $2,888,928 with a corresponding decrease to test year net income. Prior to increasing test year tax expense by $2,888,928, the Commission removed the estimated interest synchronization tax adjustment of $2,755,563 included in the supplemental filing.

O. Jurisdictional Allocation

The Commission must decide whether MP's proposed allocation to the Minnesota jurisdiction is fair and reasonable.

MP used the 12-month coincident peak (12-month CP) method in developing the allocation factors used in allocating plant and costs to the Minnesota jurisdiction. The Company argued that this method has been used for the jurisdictional allocation in several previous rate cases and is used in allocating before FERC for MP's wholesale jurisdiction.

MP also provided a capital substitution (CAPSUB) method of allocating demand costs among the retail classes. MP indicated that the CAPSUB allocation method is not used by MP for jurisdictional allocation in any of its jurisdictions.

Boise/Blandin asserted that MP increased its Minnesota jurisdictional revenue requirement by $3.2 million, through an adjustment in its allocation calculations, to recover a shortfall in the wholesale class.

The ALJ did not address this issue.

The Commission finds that MP allocated plant and costs to the Minnesota jurisdiction using the 12-

month CP method which has been approved in several previous rate cases. In keeping with the Commission's directive in Minnesota Power & Light, Docket No. E-015/GR-78-514 (April 9, 1979), MP also included a CAPSUB method of allocating demand costs among the retail classes. The dual method of the 12-month CP method for jurisdictional allocation and the CAPSUB method for class allocation was used in both Minnesota Power & Light, Docket No. E-015/GR-80-76 (January 30, 1981), and in Minnesota Power & Light, Docket No. E-015/GR-81-250 (April 30, 1982).

After applying the CAPSUB method of allocation to the classes, MP performed an adjustment to bring the amounts allocated to Minnesota classes using the CAPSUB method in line with the amounts allocated to the Minnesota jurisdiction using the 12-month CP method. The Commission finds that this adjustment does not transfer wholesale costs to the Minnesota jurisdiction. Instead, it assures allocation to the Minnesota classes of the total amount allocated to the Minnesota jurisdiction under the 12-month CP method.

Boise/Blandin stated that if MP were allowed to make this adjustment, MP would earn a 10.19% overall rate of return on a total company basis, which exceeds the 9.82% requested in this proceeding. Boise/Blandin argued that even without MP's adjustment, MP will earn a total company overall rate of return of 9.89%, still in excess of the rate of return requested in this proceeding.

The Commission finds that the rate of return set in this proceeding is limited to the Minnesota jurisdiction. MP must be allowed the opportunity to earn the allowed rate of return on its Minnesota investment. Setting Minnesota retail rates without making the adjustment would prevent MP from earning its allowed rate of return on its Minnesota investment as determined by the 12-month CP method.

The Commission finds that MP's overall total company rate of return may vary from the rate of return allowed in this Minnesota proceeding. This can result from the timing of rate change filings in different jurisdictions, different allowed rates of return in different jurisdictions, and many other variations in treatment and conditions in different jurisdictions. This is not inappropriate.

Finally, the Commission finds that if MP were to use different methods of allocating to the Minnesota jurisdiction than it used for allocating to the wholesale jurisdiction, MP would be assured of either an over- or under-recovery on a total company basis.

Based on the above findings, the Commission rejects the position of Boise/Blandin. No argument raised in this proceeding has persuaded the Commission to require a change from the basic method of jurisdictional allocation used by MP in its previous rate cases. The Commission will not adjust the revenue requirement as requested by Boise/Blandin.

P. Hibbard Boiler Amortization

In the rate base section of this Order, the Commission excluded the deferred balance of Hibbard boilers 3 and 4 from rate base. The Commission also determined that the amortization of the deferred balance to expense should be excluded. That adjustment reduces test year expense by $96,958, with an increase in test year net operating income of $57,913 after tax effects.

Q. Excess Capacity

As discussed in the excess capacity section of this Order, the Commission disallowed the Hibbard station (remaining after the donation of boilers 3 and 4 to the City of Duluth) from inclusion in the test year rate base and income statement. The income statement effect of this decision reduces test year expense by $790,000 to remove property taxes and $410,179 to remove the test year depreciation expense. This adjustment increases test year net operating income by $716,867 after tax effects.

R. Rate Case Expenses

MP proposed total rate case expenses of $1,154,510 amortized over two years. MP originally included $577,255 as test year expense, with an unamortized balance of $505,267 included in rate base.

The DPS recommended that the rate case expense of $1,154,510 be amortized over three years instead of the two years proposed by MP. MP later agreed with the recommendation made by the DPS.

The Inland Group agreed with the adjustment proposed by the DPS.

The ALJ recommended that the Commission adopt the adjustment proposed by the DPS.

The Commission has some concern about the amount of the rate case expense in this proceeding. The record, however, contains no discussion or review by the parties regarding the prudence, reasonableness, or necessity of this level of expenditure.

Furthermore, the amount requested is based on projections, not actual costs. As a result, the Commission is prevented from reviewing actual costs in making a determination. MP started with costs incurred in its last general rate case, adjusted for inflation, and added lump sum adjustments. There is little or no detail to support the figures submitted.

The Commission, however, finds that with the adjustments discussed below, MP's proposed rate case expenses are just and reasonable for purposes of this case and will be allowed. This finding is based upon the following factors: The budgeted rate case expenses are part of a reviewable budgeting process which the Commission generally has found to be reasonable. Significantly, MP has provided documents that make the budget for rate case expenses visible. These documents demonstrate that the rate case expense is based upon prior rate case experience. Moreover, rate case expenses are recognized as a normal and necessary cost of operating a public utility subject to regulation. On this basis, except for the inflation factor used in the budgeting process, the Commission concludes that MP has met its burden of proof regarding the basic facts supporting ratemaking expense.

The Commission has a significant concern regarding the level of ratemaking expenses that only the visibility of MP's budgeting process has minimally satisfied. MP's ratemaking expenses are significantly greater than the ratemaking expenses of other similar utilities in rate cases before this Commission. MP appears to include certain recurring operating expenses for its rate department in rate case expenses that other utilities also include in ratemaking but do not include in rate case expenses. While the evidence as presented allows the Commission to find MP's rate case expenses reasonable in this case, the Commission expects a greater explanation by the Company or inquiry by the parties in the future. Additionally, upon the basic facts found in MP's budgeting process, the Commission will make the following adjustments in MP's proposal.

First, the Commission will reduce the inflation factor from the 5.5% proposed by MP to the 3.81% inflation factor used by MP in rebuttal of the Inland Group's challenge to its O&M expenses.

Next, the Commission will extend the amortization of the rate case expense to three years from the two years originally proposed. The Commission finds that this is more reasonable since it was approximately six years between this filing and MP's last general rate case. Also, inflation rates have moderated and MP is not presently planning any major plant additions. These factors make it unlikely that MP will file another general rate case within the next three years. This adjustment extending the amortization period to three years is similar to that adopted in OTP, E-017/GR-86-380.

These Commission adjustments decrease test year expense by $217,243 and increase net operating income by $129,759. The moderate rate base effect will be discussed in the rate base section of this Order.

To assure that MP's estimation of rate case expense is reasonably accurate, the Commission will require MP to file on or before March 1, 1989, with the Commission and on all parties, a detailed itemization of rate case expenses. This filing should include copies of invoices from outside witnesses, counsel, and all other persons, agencies, or businesses to whom rate case expenses were paid. Also, the Commission will require MP to identify all internal corporate costs allocated as rate case expenses, together with evidence showing that no duplication has occurred in the other accounts. All such documentation shall be identified with the corresponding rate case expense projections in this filing in order to permit comparison. All such documentation shall include a statement of the period of time over which the cost was incurred, and the number of hours billed. The documentation shall explain the purpose of each cost incurred.

The Commission will approve the rate case expenses as adjusted herein contingent upon its receipt and review of the documentation requested. Further, the Commission reserves the right to adjust rates, in the May 1989 investigation ordered in NSP, MP, E-002, 015/PA-86-722, based on the rate case expense documentation supplied.

S. Historical Conservation Expense

The issue before the Commission is whether MP should be allowed to recover CIP costs incurred prior to the test year.

MP originally proposed to include $209,273 of CIP expenses incurred in 1985 and 1986, amortized over one year. MP later agreed with the recommendations of the DPS.

The DPS recommended that MP be allowed to recover $203,761 in historical CIP expenditures from the interim refund. The DPS stated that if its recommendation is accepted, test year expense would be reduced by $209,273. The DPS also proposed that if there is no refund for the interim period, the historical CIP expenses should be included in the test year in a manner similar to the rate case expenses.

The ALJ recommended that the proposal recommended by the DPS, and agreed to by MP, be accepted.

The Commission does not accept the ALJ's recommendation.

The Commission required in Order Paragraph No. 9 of the Order Approving Minnesota Power Company's Conservation Improvement Program in In the Matter of the Implementation of an Energy Conservation Improvement Program for Minnesota Power Company, Docket No. E-015/M-86-240 (October 28, 1986) that "The costs of Minnesota Power's CIP projects shall be expensed in the year that these costs are incurred." MP did not ask for reconsideration of that decision, and did not ask for differing treatment in any other subsequent docket. Therefore, MP has not had prior Commission approval to defer these costs into this rate case.

Furthermore, these costs have already been included as costs reducing MP's return on equity in Commission earnings investigations. See In the Matter of the Complaint of United States Steel Corporation Against Minnesota Power and Light, Minnesota Power, Docket No. E-015/C-84-182 (May 12, 1987). MP is therefore seeking duplicative treatment of the historical CIP costs.

Also, as MP pointed out in its objections to intervenor testimony filed September 24, 1987, costs incurred prior to the test year are irrelevant to the cost of providing service in the test year.

The Commission concludes that the historical CIP costs cannot be recovered. This adjustment reduces test year expense by $209,273 and increases net operating income by $124,999.

T. Operating Income Statement Summary

Based upon the above findings, the Commission concludes that the appropriate operating income for the test year is $55,865,552 as shown below.

Operating Revenues:			
Sales of Electricity by Rate Class	$285,142,803		
Other Electric Revenue		37,272,642	
Other Revenues		12,442,547	
Total Operating Revenues		$334,857,992	
Operating Expenses:			
Operations and Maintenance	$200,611,278		
Depreciation		28,934,373	
Amortization		444,032	
Taxes Other Than Income		34,173,140	
State Income Tax		3,191,793	
Federal Income Tax		10,043,324	
Provision for Deferred Tax (net)	4,009,405		
Investment Tax Credit		(1,860,286)	
Total Operating Expenses		$279,547,059	
Operating Income Before AFUDC			$ 55,310,933
AFUDC			554,619
NET OPERATING INCOME			$ 55,865,552

XI. RATE OF RETURN

A. Introduction

The overall rate of return authorized by the Commission is the cost of capital which is built into final approved rate levels. It represents the percentage amount which MP is allowed to earn on its rate base, or investment in its Minnesota utility operations under test year conditions.

MP's rate base is financed by three forms of capital: long-term debt, preferred stock, and common equity. The overall cost of capital is a function of the cost of each of these forms of capital and the relative amount of each form. The overall cost of capital is determined by weighting the cost of each form of capital by its proportion of the entire capital structure and summing the results.

The Commission will first address the capital structure, then the cost of debt and preferred stock, and finally the cost of equity.

B. Capital Structure

The issue to be decided by the Commission is: What are the appropriate percentage amounts of long-term debt, preferred stock and common equity to be included in the capital structure used to determine the overall cost of capital to MP?

The Commission finds that the relative proportions of the various forms of capital employed by a utility company must be reviewed to ensure that ratepayers are not being required to pay an unnecessarily high cost of capital resulting from the extravagant use of more expensive forms of capital. Because common equity is typically the highest cost capital, the equity ratio is of particular concern. Use of too much common equity in the capital structure could cause an excessive cost of capital.

The Commission recognizes, of course, that the cost of any of the forms of capital is a function of the perceived riskiness of that form. All other things equal, the more the utility company is financed with common equity, the less risky is each of the forms of capital. More common equity implies a greater likelihood that earnings will be sufficient to pay the fixed-cost obligations of interest on debt and dividends on preferred stock. In turn, the greater the equity ratio, the less those fixed-cost obligations will cause earnings available for dividends and retained earnings to fluctuate as the company experiences fluctuating sales.

The Commission must, therefore, be satisfied that the Company has established a capital structure that properly balances these two factors affecting the overall cost of capital. This is often referred to as balancing the interests of investors and ratepayers. If the Commission finds that the Company has not achieved a reasonable balance, causing ratepayers to pay an unreasonably high cost of capital, the Commission will adjust the capital structure for ratemaking purposes to put it within a reasonable range.

MP, the DPS and the Inland Group have all agreed that the following capital structure is appropriate for final, prospective rates:

Long-term debt	52.11%
Adjusted preferred stock	8.41%
Adjusted common equity	39.48%
Total	100.00%

This is also the capital structure recommended by the ALJ.

MP treated funds in its investment program as being derived proportionately from common equity, preferred stock and debt as well as from deferred investment tax credits. It considered its diversification activities as being funded fully by common equity sources, thus excluding them from the equity ratio for rate making purposes. The common equity ratio for final, prospective rates has been reduced to reflect the $67 million investment MP had planned to make in Lake Superior Paper Industries (LSPI) on April 1, 1988.

On September 21, 1987, MP submitted a request to the Commission for amendment to the Company's 1987 capital structure petition. The purpose of the filing was to allow the Company to explore or enter into a refinancing agreement on the LSPI project through MP's wholly-owned subsidiary, Minnesota Paper. One of several changes that results from the Company's request for amendment is an anticipated reduction in the level of equity investment in LSPI from $67 million to approximately $20 million. Even though this equity investment would be much less than what is currently in cost of service for the rate case, MP has not asked for an adjustment to the capital structure for final rates.

The Commission finds that MP adjusted its actual capital structure by removing its investment in its diversified operations from the common equity portion of the capital structure. The Commission finds that the resulting adjusted common equity ratio of 39.48% falls within the range of the common equity ratios of the comparable group of utilities selected for analysis by MP and the DPS.

No one disputed the propriety of using this capital structure to determine the overall cost of capital to MP, and the ALJ recommended its use. The Commission finds that the proposed capital structure strikes a reasonable balance with respect to the equity ratio, and that its use will not result in an unreasonably high overall cost of capital. The Commission concludes that the capital structure as proposed and shown above should be adopted for the purpose of determining the authorized rate of return for final rates.

MP proposed the following capital structure for interim rates:

Long-term debt	48.91%
Adjusted preferred stock	7.89%
Adjusted common equity	43.20%
Total	100.00%

This capital structure has a higher common equity ratio than that for final, prospective rates because the $67 million equity infusion into LSPI was not scheduled until the end of the test year. MP voluntarily recognized a full year's effect of the equity investment for final, prospective rates but not for interim rates.

MP was the only party to address this issue in testimony or briefs.

As discussed above in Section VII, Two Revenue Deficiencies, the Commission concluded that it is unreasonable to determine two revenue deficiencies. For the reasons stated there, the Commission rejects MP's proposal to determine a rate level for interim rates based on a separately determined interim capital structure.

In addition, the Commission finds that other factors indicate that MP's proposal is unreasonable. First, in its Order Approving Capital Structure, Minnesota Power, Docket No. E-015/S-86-145, (May 8, 1986), the Commission stated:

> Although the adjusted capital structure, as outlined above, is reasonable for the purposes of maintaining the financial integrity of the Company, the Commission specifically reserves the right to use a different capital structure for the purpose of determining the reasonableness of existing or proposed rates paid by the Company's retail customers. The Commission notes that such projected capital structure may vary depending upon the

> precise dollar amount of proceeds received by the Company from the financing applied for. The Commission notes with concern the increase in the equity component of the capital structure. The common equity ratio of the Company has risen from a test year average of 36.4% in the test year ending June 30, 1982 to an estimated 44.8% at year-end 1986. The Commission is hereby putting the Company on notice that it will have to justify this dramatic shift in it's next general rate case.

The Company has not shown that the dramatic shift from a common equity ratio of a 36.4% to the proposed 43.2% for the interim rate period was justified or appropriate. MP did not provide any testimony or evidence indicating why the increase in the common equity ratio was needed. In fact, the evidence indicates that the increase in common equity ratio was not needed for efficient utility operations. Rather, the Commission finds that the common equity ratio was increased for non-utility operations. The very fact that MP voluntarily reduced its common equity ratio for ratemaking purposes as of April 1, 1988 is an admission that the common equity ratio did not need to be higher than 39.48%. It appears that MP let its actual common equity ratio increase in anticipation of its investment in LSPI. The Commission finds that the investment in LSPI, one of MP's unregulated diversified operations, should not be allowed to negatively impact ratepayers. If MP were allowed to collect higher rates during the interim rate period because of its anticipated investment in LSPI, ratepayers would bear a portion of the cost of MP's diversified operations.

Second, in the course of the rate case investigation, the intervening parties did not examine or file testimony on MP's proposed interim capital structure. They did not have to. The ratemaking process was not designed for parties to investigate two separate revenue deficiency calculations simultaneously. This, in effect, would be performing two rate cases simultaneously, but within one ten month period. The parties appropriately examined MP's proposed capital structure for final rates. Minn. Stat. chap. 216B provides that the final rates be used to determine the appropriate refund, if any, for the interim rate period. Clearly, interim rates are designed to be temporary and provisional, subject to refund after a full hearing to determine appropriate final rates. Thus, only one final revenue deficiency need be determined, not two revenue deficiencies as proposed by MP.

C. Cost of Debt and Preferred Stock

The issue before the Commission is: What are the appropriate cost rates to apply to the debt and preferred stock component of the capital structure?

MP proposed the following cost rates:

Long-term debt	7.93%
Adjusted preferred stock	7.89%

Both the DPS and the Inland Group recommended that MP's proposed cost rates for these elements of the capital structure be approved. The ALJ also recommended that MP's proposed cost rate for debt and preferred stock be approved.

The OAG argued that a financial adjustment should be made because MP has a capital base which exceeds its utility rate base. The OAG stated that the Company has taken some of its total capital structure (common equity, preferred stock and long-term debt), along with all of its accumulated deferred investment tax credits (ADITCs) and invested the capital in a securities and other investment program. The OAG asserted that MP has manipulated the allocation of capital costs in a manner that results in MP's shareholders receiving not only the exclusive benefit of ADITCs, but also an unjust benefit from tax-exempt debt. The OAG argued that MP should instead have provided its ratepayers with the lowest reasonable cost of capital. The OAG claimed that if MP had allocated all of its lowest cost debt and preferred stock to its utility operations, rather than using some of that lower cost capital to benefit its shareholders, the ratepayers would have saved approximately $2.7 million.

The OAG proposed three alternative solutions to this problem: 1) Recalculate the cost of capital by allocating the lowest cost debt, preferred stock and ADITCs to utility operations rather than to shareholder activities; 2) Put the securities and other investment program capital in the rate base and the income from that program in the income statement; or 3) Calculate the interest expense for tax purposes using MP's actual budgeted interest rather than the interest synchronization method.

MP responded that the retirement of debt or preferred stock would produce no reduction in the embedded cost of capital and, considering administrative expenses and cost, might produce higher costs. MP stated that it used its excess capitalization over rate base to retire debt where significant savings could be achieved. MP also stated that its proposed capital structure treats the funds in the securities and other investment program as being derived proportionately from common equity, preferred stock, and debt as well as from ADITCs.

The ALJ concluded that all three of the alternatives proposed by the OAG should be rejected.

The Commission finds that MP's capital base exceeds its rate base by approximately $240 million. MP could have chosen either to reduce its capital base or to invest its excess capital in non-utility operations. To reduce its capital base, MP could have retired debt and preferred stock, and either increased its dividend or purchased MP stock on the open market. MP could have reduced its capital base, leaving the relative amounts of capital in its capital structure unchanged. Instead, MP chose to invest in diversified activities, mostly through its wholly owned subsidiary Topeka Group, and to create a securities and other investment program.

The Company decided to consider diversification activities as being funded fully by common equity sources for ratemaking purposes. This reduced the equity ratio in the capital structure. Because equity is MP's highest cost source of capital, this decision had the effect of reducing the cost of service for utility ratepayers. For ratemaking purposes MP decided to consider its securities and other investment program as being funded proportionately from common equity, preferred stock, and debt as well as ADITCs. MP has not included the earnings from its securities and other investment program in the determination of the utility revenue requirement. MP has also not included these assets in the utility rate base.

MP's rationale for treating its diversification activities and its securities and other investment program differently is that securities are held in the investment portfolio pending reinvestment in utility property or redemption. However, MP has also treated the securities and other investment program differently than utility investments in order to insulate ratepayers from the risk of that investment activity. Thus, the securities and other investment program is treated neither like utility investment nor like other non-utility investment.

The Commission finds that the existence of the securities and other investment program did not cause an increase in MP's embedded cost of debt or preferred stock in the test year. MP's April, 1987 refinancing of its higher cost debt and preferred stock reduced revenue requirements to ratepayers by $1.2 million. MP could have retired, rather than replaced, these and other issues since the capital was not needed for electric utility purposes. The excess funds were invested in non-utility operations. The Commission finds that out-right retirement rather than replacement would not have reduced the embedded cost of debt as alleged by the OAG, although it would have improved MP's fixed charge coverage ratio. Thus, while MP's actions did not directly increase the cost of debt, the failure to retire debt increased the perceived risk of investment in MP's common stock. This is true because non-utility investments may be perceived by investors as more risky than a utility investment and because of a lower fixed charge coverage ratio. The Commission finds that MP's proposed equity cost improperly reflects the added financial risk caused by MP's non-utility operations.

The Commission finds that MP has used capital generated as a result of its electric utility business as a source of capital for its non-utility investments, including its securities and other investment program. Because of a utility's favorable tax status and the use of MP's good name, the cost of borrowing to MP is lower than to an independent investor who borrows capital for the purpose of investing it. MP has used the resources of its electric utility operations for non-utility purposes. It has, in essence, proposed that the securities and other investment program pay the regulated operations by assigning all capital in excess of rate base to the unregulated side at the overall cost of capital. By so doing, MP has inextricably mixed its utility and non-utility operations. It appears that there are no contractual arrangements and no separate accounting of the funds flow, administrative expenses, or earnings between MP's utility operations and the securites and other investment program. MP refused to provide information concerning the earnings of its securities and other investment program to the OAG. MP management has carefully carved out the very profitable securities and other investment program from utility operations. One reason the securities and other investment program is profitable is due to the low cost sources of capital available from utility operations to finance the investments. The utility capital structure includes tax exempt pollution control bonds, and ADITCs at zero cost.

The Commission finds that MP's commingling of utility and non-utility capital and its arbitrary division of diversified activities (funded by common equity) and its securities and other investment program (funded by the full capital base) has produced a mixed result for MP ratepayers. The record evidence indicates that MP's securities and other investment program did not increase the embedded cost of debt or preferred stock for ratemaking purposes. However, MP did not share any of the securities and other investment program earnings in the test year with the utility operations from which it derived the low cost source of capital for investment. Further, MP's failure to retire debt caused an increase in the fixed charge coverage ratio.

The Commission considered several alternatives to resolve this issue. For the reasons stated in Section X, item N. Interest Synchronization, the Commission rejects the OAG recommendation not to use interest synchronization in this case.

Also, the Commission will reject the OAG recommendation that the earnings from the securities and other investment program be included for ratemaking purposes. The required earnings information was not a part of the record, nor was there a careful review of the types of investments included in this program. It is not clear that ratepayers should be exposed to the risks in the securities and other investment program.

The Commission also considered the OAG suggestion to allocate $240 million of the highest cost capital to the securities and other investment program taking the funds proportionately from debt, preferred stock, and common equity. This would have the desired effect of recognizing that the low cost and tax-exempt debt was required for utility purposes. However, the record does not show whether the resulting reduction in revenue requirements of approximately $2.7 million would compensate ratepayers for the Company's increased risk caused by the securities and other investment program. The Commission notes that the exhibits showing this adjustment were introduced during cross examination rather than through the prefiled, direct testimony of an expert witness. Thus, the full impact of this proposal was not fully explored on the record. For this reason, the Commission does not consider this alternative to be appropriate.

Further, the Commission will not find that the securities and other investment program should be funded solely from common equity sources in the same manner as the diversified activities. The effects of this alternative were not explored in the record. Clearly, a reduction of $240 million from the common equity portion of the capital structure would have a profound effect on the overall rate of return, all other things equal. Also, this alternative would not reflect MP's intent to hold the securities and other investment program as a ready source of capital for electric utility operations.

The Commission does, however, share the concerns expressed by the OAG. On the basis of this record, the Commission finds there is an alternative method which better addresses these concerns. The Commission finds that as a result of its securities and other investment program, MP has increased risk and that an adjustment to the cost of equity, rather than to the cost of debt, is appropriate. The Commission finds that this provides the most appropriate resolution of this issue. The Commission concludes that it will reduce the return on equity allowed to MP in order to insulate ratepayers from the added risk caused by MP's securities and other investment program. This adustment is discussed under the Cost of Common Equity below.

D. <u>Cost of Common Equity</u>

The Commission must next determine a fair and reasonable return on common equity for MP.

MP requested a return on common equity of 12.75%. The DPS recommended that the Commission find the cost of equity to the Company to be no greater than 12.5%. The Inland Group recommended that the Commission find the cost of equity to MP to be 11.51%. The OAG recommended that the Commission find the cost of equity to MP to be in the range of 11.51% to 12.2%.

The ALJ recommended that the Commission authorize a return on common equity of 12.5% for MP.

In reaching a decision on the appropriate cost of common equity, the Commission, as an administrative agency, must act within both the scope of its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide these general guidelines for Commission rate of return decisions:

(a) The allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties.

(b) The return should be sufficient to enable the utility to maintain its financial integrity.

(c) The return should be sufficient to attract new capital on reasonable terms.

See Bluefield Water Works & Improvement Co. v. P.S.C., 262 U.S. 679 (1923), and FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

No particular method or approach for determining a rate of return was mandated by those cases, but the necessity of a fair and reasonable rate of return was clearly stated:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.
> Bluefield Water Works, 262 U.S. at 690.

The Minnesota Supreme Court has also provided some legal guidelines for Commission decision-making. In Minnesota Power & Light Company v. Minnesota Public Utilities Commission, 302 N.W.2d 5 (1980), the Court said:

> . . . The single term "ratemaking" has been used to describe what is really two separate functions: (1) the establishment of a rate of return, which is a quasi-judicial function; and (2) the allocation of rates among classes of utility customers, which is a quasi-legislative function.
>
> . . . we now hold that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.
>
> 302 N.W.2d at 9.

In conducting its evaluation of the Commission's decision, the Court explained:

> . . . A reviewing court cannot intelligently pass judgment on the PSC's determination unless it knows the factual basis underlying the PSC's determination. Judicial deference to the agency's expertise is not a substitute for an analysis which enables the court to understand

> the PSC's ruling. Henceforth, we deem it necessary that the PSC set forth factual support for its conclusion. The PSC must state the facts it relies on with a reasonable degree of specificity to provide an adequate basis for judicial review. We do not require great detail but too little will not suffice.
>
> 302 N.W.2d at 12.

In order to make its determination of the appropriate rate of return on common equity, the Commission has reviewed the testimony of all parties, the objections raised thereto by the other parties, and the recommendations of the ALJ. The Commission will draw its conclusions from the evidence presented and its own expertise, and will set forth the factual basis for its decision as required by the Court.

Common equity has a cost determined in the capital market by forces acting on the market as a whole, such as inflation and the general economic outlook, and by concerns peculiar to the specific industry and the specific company. Unlike holders of debt or preferred stock, common shareholders have no contractual right for specified payments. Instead, they have an ownership claim on the residual amounts after interest on bonds and dividends on preferred stock have been paid. Because of this, the cost of common equity cannot be measured directly, but can only be estimated.

In this proceeding, DPS witness Dr. Luther C. Thompson, Inland Group witness Dr. Jay B. Kennedy, and the ALJ all relied primarily on a discounted cash flow (DCF) analysis to make the cost of equity estimate. Mr. Zvi Benderly, witness for MP, recommended a cost of equity based on a combination of a DCF analysis and a risk premium analysis.

Under the DCF method, the cost of equity is inferred by observing past and present market data on the price of the stock and the dividend being paid, and by making reasoned judgments of investor expectations for the future. Investors collectively determine the market price of common stock by their willingness to buy or sell the stock at various prices. Essentially, the DCF analyst is trying to determine what interest rate investors are using to discount the expected future flow of dividends and stock price appreciation to a present value equal to the current price of the stock. That interest rate is the market-required rate of return. The DCF analyst generally makes use of a formula in which the required rate of return is equal to the sum of the dividend yield (the dividend divided by the price) and the growth rate expected by investors.

The Commission finds that the DCF approach is appropriate to use to estimate the cost of equity to MP in this proceeding. The Commission finds that the DCF method is firmly grounded in modern financial theory and has been relied on by the Commission in nearly every rate case proceeding since 1978. A fair and reasonable estimate for the cost of capital should be based on past evidence and reasonable judgments concerning future expectations.

1. Summary of Testimony

Mr. Benderly testifying for MP, performed both a DCF analysis and a risk premium analysis to estimate the cost of equity to MP's electric operations.

Mr. Benderly relied solely on an analysis of a comparison group of companies as the basis for his DCF study. He did not apply the DCF method directly to MP market data because MP's electric operations alone do not have common shares which are publicly traded. Since MP has a very profitable investment portfolio as well as substantial diversified operations, the market price of MP stock reflects investors' evaluations of the Company as a whole, including diversified operations and the investment portfolio, not solely its electric operations. Mr. Benderly employed eight selection criteria to choose a sample of companies which were comparable to MP's electric operations. Mr. Benderly applied a DCF analysis methodology to the ten companies which met all eight selection criteria. He then performed a separate risk study to account for other risk differences between the comparison group and MP's electric operations.

Mr. Benderly determined the dividend yield, the first component of the DCF formula, to be 6.6% to 7.02%. He increased the dividend yield range by a factor of approximately 1.024 to reflect one half the expected growth in dividends over the next year. Mr. Benderly selected 7% as the appropriate dividend yield, a figure which is approximately the midpoint of his adjusted dividend yield range. To determine the growth rate component of the DCF formula, Mr. Benderly looked at historical growth rates, internal growth rates, and projected growth rates. He estimated an investor's expected growth in dividends to be within the range of 4.5% to 5.0%, with a midpoint of 4.75%. Combining this growth rate with his dividend yield of 7%, he found a DCF-determined bare bones cost of equity for the comparison companies of 11.75%.

Mr. Benderly also performed a risk premium analysis in which he compared the returns earned on common stock with the returns earned on government bonds over the last 60 years. The result was adjusted to reflect the lower risk of the common stock of the comparison group of utilities, compared to all common stocks, to compute a risk premium for the comparable companies. Mr. Benderly added this risk premium to the current return on long term government bonds to determine a cost of equity for the comparison companies of 12.87%.

Mr. Benderly averaged the results of his two analyses, assigning a weight of one-third to the risk premium study and a weight of two-thirds to the DCF study, to determine a weighted average cost of equity of 12%.

Finally, Mr. Benderly performed a relative risk analysis of the comparison companies and the electric operations of MP, comparing ten financial and operational attributes. He concluded that the risk and cost of equity of MP's electric operations is higher than that of the comparison companies. He also compared the revenue mix and the relative variability of MP and the comparison companies, finding that industrial customers make up a much larger portion of MP's business and that MP's electric operations exhibited a much higher degree of variability in revenues and income. Mr. Benderly concluded that due to MP's higher risk, the cost of common equity for MP is one percentage point greater than the bare bones cost of equity for the comparison companies.

Dr. Thompson testifying for the DPS, performed two DCF analyses. He applied the DCF method first to data concerning MP itself and second to data for a group of ten comparable utilities. Ultimately, Dr. Thompson based his cost of equity recommendation on the DCF analysis applied to MP data.

Dr. Thompson's group of ten utilities was the same group used by Mr. Benderly. He compared MP to the selected comparable group using four criteria: Value Line's measure of beta, financial strength, price stability and safety. Based on that comparison, he concluded that MP is risk comparable to the group.

Dr. Thompson calculated the average dividend yield for three recent 20-day periods and for the most recent one- and two-year periods. He then determined the range of the high and low figures in those periods and selected a dividend yield near the midpoint of the range. The selected dividend yield for MP is 6.25%. Following the same approach, he determined the dividend yield range for the comparable group to be 7.0% to 7.5%.

To estimate the growth component of the DCF-derived cost of equity for MP and the comparable group, Dr. Thompson looked at 5 and 10 year historical data reflecting compound and log linear growth rates (adjusted and unadjusted) in book value, earnings and dividends per share. He also considered internal growth rates. He estimated an expected dividend growth rate for MP to be in the range of 5% to 7%, with 6.25% as a reasonable upper estimate. Applying the same method to the data for the comparable groups, Dr. Thompson concluded that a reasonable dividend growth rate for the comparable group is 4% to 5%.

Dr. Thompson estimated that MP's cost of equity is 12.5%, based on a yield of 6.25%, and a growth rate of 6.25%. Using a range of 7% to 7.5% for the dividend yield and a range of 4% to 5% for the growth rate for the comparable group, Dr. Thompson concluded that a reasonable range for the cost of equity for the comparable group is 11% to 12.5%, with a mean of 11.75%. Based on these analyses, Dr. Thompson concluded that 12.5% is a reasonable upper-limit for the current cost of equity for MP.

Dr. Kennedy, testifying for the Inland Group, performed a DCF analysis applied to a comparable group of utilities. Dr. Kennedy, like Mr. Benderly, did not apply his DCF analysis directly to MP market data, because MP capital has been invested in non-utility assets. Dr. Kennedy asserted that the return on equity determined by the Commission should reflect only what would be required by investors to provide capital for use in regulated electric operations. Dr. Kennedy used several criteria, including bond rating, Value Line safety rank, and lack of nuclear exposure, to select his group of comparable companies. Dr. Kennedy then applied his DCF method to the 14 companies meeting his selection criteria.

Dr. Kennedy calculated the six-month average dividend yield for the group of comparable companies for the period ending June, 1987 to be 6.6%. He adjusted this figure by one-half the growth rate to account for dividend increases expected over the next year, to determine a recommended dividend yield of 6.76%. Next, Dr. Kennedy estimated investor-expected growth rates for the comparable companies by computing a weighted average of the historical growth in earnings per share, historical growth in book value per share, forecast dividend growth, and compound growth in dividends over a five year period. Dr. Kennedy determined that the cost of equity for his comparable group of companies is 11.51%, based upon a dividend yield of 6.76% and a growth rate of 4.76%.

Dr. Kennedy performed a risk premium study as a check on the results of his DCF study. He determined the difference between the cost of equity and the cost of debt to the comparable group to be 1.44%. He then added this risk premium to MP's cost of debt over a recent six month period, resulting in a risk premium cost of equity of 11.42%. Dr. Kennedy argued that this check tended to confirm the DCF-calculated cost of equity of 11.51% is reasonable.

The ALJ found that the appropriate cost of common equity for MP is 12.50%, based on Dr. Thompson's DCF analysis applied to MP market data.

2. Commission Discussion

a. Validity of DCF Analysis Applied to MP Data

The Commission first must decide whether it is reasonable and appropriate to apply the DCF analysis to MP data.

The Commission agrees with Mr. Benderly and Dr. Kennedy that it is not reasonable to apply the DCF approach directly to MP data, because MP's electric operations by themselves do not have common equity shares which are publicly traded. The Commission finds that the MP stock that is traded represents not only its electric operations, but all of MP's unregulated operations as well. A relatively significant part of MP's net income is from non-electric operations, and income is the driving force behind stock prices and market evaluation. The market price of MP's stock reflects investors' evaluations of the Company as a whole, including its diversified operations and its investment portfolio as well as the electric operations.

In discussing MP's risk factors, Mr. Benderly noted Credit Week's concern about the Company's expanding and increasingly aggressive diversification efforts. Likewise, Dr. Thompson's exhibits included a Value Line report stating "MP&L's foray outside of its core business adds some uncertainty."

The Commission finds that MP's utility and non-utility operations are not seen by investors as entailing similar risk. Thus, the required return for each portion of the Company's operations is different. The Commission further finds that because investors perceive non-utility operations as riskier than utility operations, Dr. Thompson's 12.5% estimate of the cost of equity overstates the cost of equity for MP's regulated operations.

Therefore, the Commission finds it is necessary to analyze the cost of equity of a group of utilities with comparable risk to MP's electric operations. The Commission concludes a DCF-determined cost of equity to a comparable group is a suitable proxy for the cost of equity for MP's electric utility operations.

b. Relative Risk Analysis

Next, the Commission turns to the question of whether Mr. Benderly's relative risk analysis demonstrates that the cost of equity to MP's electric operations is greater than the cost of equity to the comparison group.

The DPS argued that Mr. Benderly's proposal to add 100 basis points to the cost of equity should be rejected because this proposal defeats the entire purpose of looking at a comparable group to determine the cost of common equity for a company. Dr. Thompson performed an independent review of Mr. Benderly's group of comparable companies and found them to be risk comparable to MP based on four risk criteria used by investors.

The Inland Group asserted that Mr. Benderly's adjustment drifted well out of the mainstream of cost of equity analysis and that there is simply no evidence in the record that the investment community would exact a 100 basis point premium for the various risks associated with MP. Further, they argued that it is impossible to check the reasonableness of Mr. Benderly's assertion because his premium is totally arbitrary and subjective. This adjustment is simply too unreliable and judgmental to produce consistent results from one utility to another.

The OAG also argued that the Commission should reject Mr. Benderly's relative risk analysis, because there is no quantifiable basis for his 100 basis point adjustment. The OAG stated that conventional financial measuring techniques have already accounted for the risks associated with MP's operations. The DCF analysis, which compares a variety of risk indicators, is completely adequate for measuring MP's cost of capital.

MP responded that investors use many risk indicators other than those looked at by Dr. Thompson in forming their assessments of a company. Mr. Benderly's risk analysis indicated that MP's electric operations would be regarded by investors as riskier than the comparison companies. Further, two of Dr. Thompson's factors indicated that MP had greater risk than the comparison companies, while the other two indicated about equal risk.

The ALJ found that there is no significant risk difference between MP and the comparable group and therefore there is no foundation for the 100 basis point adjustment proposed by MP.

The Commission agrees with the DPS, the Inland Group, the OAG and the ALJ on this issue. The Commission finds that Mr. Benderly's proposed adjustment is unwarranted. There must be both a sound basis for the judgment that MP is more risky than the comparable group as well as a reasonably objective method for quantifying the result. The Commission finds that MP's relative risk analysis lacked both.

First, the Commission finds that Mr. Benderly's proposed adjustment is not conceptually sound. He chose eight objective criteria to determine his comparable group. The ten utilities were selected because they met the criteria and thus are risk comparable to MP. The Commission finds that it is illogical for Mr. Benderly to argue that 100 basis points should be added to MP's cost of equity on the basis of his own comparison.

Second, the Commission agrees with the OAG and the Inland Group that there is no quantifiable basis for Mr. Benderly's proposed adjustment.

Third, the Commission notes that Dr. Thompson's analysis of Mr. Benderly's comparison group indicated that MP is risk comparable to the group. The Commission recognizes that Dr. Thompson's analysis was based on MP's total Company financial position, not just the electric utility. Because

MP's diversified operations add to risk, the Commission finds that MP's electric operations may be less risky, rather than more risky, than the comparable group. This finding invalidates Mr. Benderly's proposed adjustment. The Commission concludes that the proposed adjustment is unreasonable.

c. Risk Premium Studies

The Commission next turns to the question of whether the risk premium studies presented by Mr. Benderly and Dr. Kennedy provide a reasonable estimate of the cost of equity to the comparison group.

The DPS, the OAG and the ALJ all recommended that the risk premium method not be used to estimate the cost of equity of MP's electric operations. MP argued that Dr. Kennedy's risk premium analysis was fraught with errors.

The Commission agrees that it is inappropriate to use a risk premium analysis to determine the cost of common equity. The risk premium method has not been shown to be a reliable indicator of the cost of equity. The Commission has consistently rejected this approach for estimating the cost of equity because of the volatility of results from this method. Nothing in this record demonstrates its that policy should be changed. The Commission also finds that Dr. Kennedy's risk premium analysis can not be used as a check on the DCF results, since one of the primary inputs into his calculation is the DCF result itself.

d.DCF Analyses of Comparable Groups

Next, the Commission will address the issue of which DCF study applied to a comparable group provides the best estimate of the cost of equity to MP.

The unadjusted DCF estimates of the cost of equity to MP, based upon the analysis of a comparable group, fell within a relatively narrow range. Mr. Benderly's unadjusted DCF study indicates a cost of equity of 11.75%. Dr. Thompson's DCF study indicates a cost of equity in the range of 11.0% to 12.5%, with a midpoint of 11.75%. Dr. Kennedy's DCF study, based on a different comparable group, shows a cost of equity of 11.51%.

The results of these analyses indicate that there is more agreement than disagreement among the witnesses. The Commission finds that all studies were generally credible and provide an indication of the cost of equity to MP. However, the Commission does not agree with all of the judgments and calculations made by the rate of return witnesses.

The Commission will first discuss the comparable group DCF studies performed by Mr. Benderly and Dr. Thompson.

The first component of the DCF-determined cost of equity is the dividend yield. The dividend yield should reflect current conditions, yet it should not be unduly influenced by temporary market fluctuations. It must be recognized that the rate of return allowed in this proceeding will partly determine the rate level for at least one year, and possibly much longer.

The Commission finds that Mr. Benderly's proposed unadjusted dividend yield range of 6.60% to 7.02% provides the most reasonable dividend yield for use in estimating of the cost of equity to the comparable group. The 6.60% is the twelve month average dividend yield for the comparable group for the period ending July, 1987. The 7.02% is the average of the one-, three-, six-, nine-, and twelve-month average dividend yields for the comparable group in the period ending July, 1987. The Commission finds that Mr. Benderly's dividend yields provide a better balance of current and longer term yields than does Dr. Thompson's average of 20-day, one-year, and two-year yields. The Commission finds that Mr. Benderly's averaging of monthly, quarterly and annual dividend yields reasonably reflects current market conditions, is representative of investor expectations for the regulatory period, and is long enough to smooth the effect of any temporary market fluctuations. The Commission concludes that the midpoint of this range, 6.81%, is the most reasonable estimate of the dividend yield for the comparable group.

The Commission rejects Mr. Benderly's proposal to adjust the dividend yield by one-half the growth rate to reflect investor expectations of growth in the dividend in the next year. The Commission finds in this case, as it has found in several previous cases, that there is no basis for this adjustment. See Peoples Natural Gas Company, Docket No. G-011/GR-86-144 (January 16, 1987) at 43; Northern States Power Company, Docket Nos. G-002/GR-86-160, G-002/M-86-165 (January 27, 1987) at 47; United Telephone Company of Minnesota, Docket No. P-430/GR-84-597 (August 12, 1985) at 21. There is no evidence that investors make this adjustment when evaluating common stock purchases. Further, investors' expected growth in dividends is already reflected in the growth term in the DCF analysis. Hence, adjusting the dividend yield for the expected growth would double count this growth expectation.

The Commission next turns to the appropriate growth rate to use in the DCF equation.

The growth rate should reflect the constant rate at which investors expect dividends to increase in the future. To estimate investor expectations, it is reasonable to presume that investors consider historical growth rates, current internal growth rates, and projected growth rates. All the analysts presenting rate of return testimony in this proceeding considered all or most of these factors.

The Commission finds there is little controversy concerning the appropriate growth rate range. Using the same comparable group, Mr. Benderly recommended a growth rate range of 4.5% to 5.0%, while Dr. Thompson recommended a range of 4.0% to 5.0%. The Commission finds that Mr. Benderly's growth rate range of 4.5% to 5.0% provides the best estimate of investors' expected growth. This range is more reflective of the range of growth figures presented in the record. The Commission finds that the midpoint of this range, 4.75%, is the most reasonable estimate of investors' growth expectations. This growth rate of 4.75% falls within Dr. Thompson's range, providing further support for the reasonableness of this selected growth rate estimate.

Combining the 6.81% dividend yield with the 4.75% expected growth rate results in a cost of equity of 11.56%, based on a DCF analysis of the comparable group selected by Mr. Benderly and Dr. Thompson.

The Commission next turns to the DCF analysis performed by Dr. Kennedy.

As discussed above, Dr. Kennedy recommended a cost of equity of 11.51%, based on his comparable group study of 14 utilities. The ALJ found that Dr. Kennedy's comparison group was not risk comparable to MP, implying that they were generally less risky.

The Commission does not agree that Dr. Kennedy's group is less risky than MP. One of the measures used by Dr. Kennedy to compare MP's risk to that of the comparable group was the fixed-charge coverage ratio. However, MP's fixed-charge coverage ratio is significantly affected by its decision to invest in its securities and other investment program. As discussed earlier, MP's stockholders are receiving significant benefits from this program, and MP's ratepayers should be insulated from the effects of these non-utility investments. While the record does not indicate what the fixed-charge coverage ratio would be if MP had retired debt or preferred stock instead of investing in its securities and other investment program, the Commission finds that MP is clearly more risky because of its securities and other investment program. Therefore, it cannot be concluded that Dr. Kennedy's group is less risky than MP would be absent the securities and other investment program.

The Commission finds that the DCF-determined cost of equity of 11.56% discussed above is the best estimate of the cost of equity for MP's electric operations. This result is based on a group of utilities which the Commission has found is risk comparable to MP's electric operations. Dr. Kennedy's DCF analysis, based on a different comparison group of utilities indicating a cost of equity of 11.51%, directly confirms the reasonableness of the 11.56% Commission-determined cost of equity. This result also reflects the Commission's judgment that the allowed return of equity should be set toward the lower end of the cost of equity range to protect ratepayers from the increased risk caused by MP's non-utility investment activities.

E. Overall Rate of Return

Based on the Commission's findings and conclusions on return of equity, cost of debt and preferred stock, and capital structure made herein, the Commission concludes the overall rate of return for MP in the test year is 9.35%, calculated as follows:

	% of Total	Cost	Weighted Cost
Long-Term Debt	52.11%	7.93%	4.13%
Adj. Preferred Stock	8.41%	7.89	.66%
Adj. Common Equity	39.48%	11.56	4.56%
	100.00%		9.35%

XII. REVENUE DEFICIENCY (SURPLUS)

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue surplus of $8,500,076 determined as shown below.

Rate Base	$543,192,064
Rate of Return	9.35%
Required Operating Income	50,788,458
Test Year Net Operating Income	55,865,552
Operating Income Deficiency (Surplus)	(5,077,094)
Revenue Conversion Factor	1.674201
Revenue Deficiency (Surplus)	$ (8,500,076)

In the test year income statement, the Commission found that revenue from sales of electricity by rate class at present rates is $285,142,803. Subtracting $8,500,076 from $285,142,803 results in total authorized Minnesota revenues from sales of electricity by rate class of $276,642,727.

XIII. RATE DESIGN

A. Class Revenue Responsibility

1. Class Cost of Service Studies

The issue before the Commission is which class cost of service study provides the best cost information for guidance in determining appropriate class revenue allocations.

MP's embedded class cost of service study is a variant of the average and excess method, using a capital substitution, or CAPSUB, model to classify power supply production costs as capacity-related and energy-related. Another component of MP's study is the average and excess/probability of deficiency, or A&E/POD, model for determining how capacity-related and energy-related fixed costs, transmission-related costs, and energy costs are allocated to costing periods and subsequently to classes. MP used a normalized load factor for the Large Power (LP) class of 77.5% in developing allocation factors in this study. MP changed the way it determined "equivalent customers" for the Lighting class, resulting in fewer Lighting customers and thereby assigning a lower level of cost responsibility to the Lighting class.

The DPS embedded class cost of service study method was similar to that of MP in many respects. The most significant difference between the studies was the DPS use of a "peaker substitution" method for classifying power supply production costs as demand- and energy-related. The DPS also differed with MP in the allocation of transmission and conservation costs. In addition, the DPS presented, for informational purposes, a short-run marginal cost study, using the reactivation of the Hibbard units as a proxy for marginal generation costs.

The Seniors performed a long-run incremental, or marginal, cost study using a coal-fired unit as the primary measure of marginal generation costs, and recommended that the study be the basis for determining the Residential class increase and rate design.

The Inland Group claimed the costs derived from MP's CAPSUB method were more meaningful than marginal cost studies, but argued that MP should be ordered to rerun its study using a test-year budgeted LP load factor of at most 73.2%. Boise/Blandin generally supported the MP cost study, but disagreed on the assignment of energy costs to costing periods.

The ALJ recommended that the DPS embedded class cost of service study be adopted, approving the DPS handling of power supply production costs, transmission costs, conservation costs, and AFPO gain. The ALJ rejected the Seniors' marginal cost study, and recommended that the DPS marginal cost study not be adopted, but used for informational purposes only, because it resulted in an impractically high estimate of Residential class cost.

The Commission agrees with the ALJ that the two marginal cost studies should not be adopted for revenue allocation purposes. Neither study provides useful guidance for class revenue responsibility in this proceeding, because of the high degree of uncertainty and subjectivity introduced in reconciling marginal costs to the revenue requirement. However, the Commission disagrees with the ALJ that the DPS embedded class cost of service study is superior to that of MP. The record evidence does not show that the DPS peaker-substitution method is superior to the MP CAPSUB method adopted by the Commission in both the 1980 and 1981 MP rate cases. In those proceedings, the Commission found the CAPSUB method properly recognized that a high load factor utility such as MP invests in more costly base load units in response to off-peak energy use, not just system peak needs, and avoided the over-assessment of demand costs to low load factor classes. The Commission reaffirms those findings.

The Commission finds that the MP method, which was also used by the DPS, for allocating energy costs to costing periods is appropriate. The Commission disagrees with Boise/Blandin's position that the lower fuel costs of base-load plants should be credited only to off-peak periods. Since the operating loads during the secondary and peak periods, as well as off-peak periods, influence the type of plant built by MP, the fuel savings from base-load plants should be recognized in all periods.

The Commission finds it reasonable to classify conservation-related costs as one-half energy and one-half demand as recommended by the DPS. The Commission adopted this method in NSP, E-002/GR-85-558 and OTP, E-017/GR-86-380. Conservation programs are undertaken to reduce or manage energy and demand, not the number of customers. However, conservation-related costs are a relatively small portion of MP's total cost of service; therefore this change would have an insignificant practical effect on the outcome of the cost study.

The Commission notes that the cost responsibility assigned to each class under the DPS and MP embedded cost studies does not differ greatly, and when the difference in AFPO gain allocation method is considered, the difference is even less. Both studies show the LP and Lighting classes paying rates over cost, the Municipal Pumping and Large Light and Power (LL&P) classes moderately below cost, the General Service class slightly under cost, and the Residential class more than 50% below cost. The similarity in the results of these two studies increases the Commission's confidence in using MP's results for guidance in revenue allocation decisions. The Commission concludes that the results of MP's embedded class cost of service study method provide the best information in the record on the costs to serve MP's customer classes. However, the Commission will order MP to revise its method of classifying conservation costs in future studies as described above.

The Commission must caution that a class cost of service study is only a starting point for determining reasonable class revenue responsibility levels. As the Commission stated in MP, E-015/GR-81-250:

> The Commission believes that class cost of service studies provide an important starting point for determining class revenue responsibilities. However, such studies have limitations and cannot claim to be precise measures of cost. The Commission continues to find that other cost and non-cost factors may properly be taken into account when setting class revenue requirements. . . .

The Commission continues to find these statements appropriate; other cost and non-cost factors may, and should, be taken into account when determining class revenue responsibility. In the particular circumstances of this proceeding, the Commission finds the value of the class cost study for determining class revenue allocations is more limited than usual due to other cost factor considerations. Non-cost considerations are discussed in the next section.

The recent contract demand reductions by LP customers and a lower LP load factor were built into both the MP and DPS embedded cost studies. As pointed out by the OAG and the Seniors, these current usage patterns do not reflect historical usage nor the reasons behind MP's past plant expansion. In MP, E-015/GR-81-250, the cost study adopted by the Commission used normalized LP load factors, which kept the LP revenue allocation closer to historical plant use, even though LP use for the test year was budgeted at lower levels. The relatively minor adjustment from forecasted test year LP load factor of 73.2% to a "normalized" load factor of 77.5% made by MP in its study is still considerably less than the adjustment required to reach the load factor of approximately 86% used in the last case. Therefore, the Commission finds that MP's cost study tends to understate the appropriate LP cost allocation, and consequently to overstate that for other classes.

In addition, the Commission has found a revenue requirement of approximately $276 million, compared to the revenue requirement of $292 million used in MP's class cost of service study. Because the Commission's revenue requirement is significantly lower, the Commission finds the class cost responsibilities resulting directly from the study will tend to be less accurate than is normally the case. Simply assuming that proportional decreases would result for all classes would not be appropriate. Lastly, the various proposed treatments of the AFPO gain introduced additional uncertainty into the results of the cost studies presented.

2. Class Revenue Allocation

The next issue is the appropriate share of MP's revenue requirement to be collected from each customer class. A secondary issue is whether the revenue allocation decisions made herein should be maintained in the investigations of the Boswell 4 transfer.

MP proposed to increase Residential rates by 15%, regardless of the final revenue level set by the Commission. MP also proposed to assign a uniform class rate of return to all other classes except the LP class for which the class rate of return would be 1% higher than that of other non-residential classes. The OAG recommended that the Residential class receive a proportional decrease from MP's proposed revenue responsibility for any lower overall revenue level set by Commission. The Superwood Group and the Inland Group supported MP's proposal for the Residential class. However, the Inland Group argued that there should be no 1% risk premium assigned to the LP class. The DPS proposed revenue allocation was based on its cost study and non-cost factors; DPS recommended a 13.46% increase in Residential rates at MP's revenue requirement, with a proportional decrease at any lower overall revenue level. The Seniors recommended that the Residential class receive the overall percentage increase. Boise/Blandin recommended a 25% increase to the Residential class regardless of the final revenue level and opposed any risk premium for the non-taconite LP customers; LSPI supported these recommendations. Potlatch recommended applying any decrease from MP's proposed revenue level first to the initial block of the LP demand charge, next to the LL&P class, and finally proportionately to all classes except Residential.

The ALJ adopted the DPS proposed class revenue allocations, based on the DPS embedded cost study and recognition of non-cost factors. The ALJ claimed an increase for Residential customers of 13.46% after more than six years was not unreasonable. He found it appropriate to decrease LP rates by 3.85% to move the rates closer to cost and recognize the class' current subsidy of the Residential class, indicating that any greater decrease would have severe impacts on other classes. The ALJ stated that Residential and General Service customers in MP's service area have undergone significant economic hardship since the last rate case, as have most larger employers comprising the LL&P and LP classes. The ALJ found the taconite intervenors have already received a limited rate reduction since the last rate case through contract demand reductions and participation sales.

The Commission agrees with the ALJ that all customer groups in MP's service area have suffered economic hardships since the last rate case. Many Residential customers have been particularly hard-hit as can be seen from the statistics on personal income, employment, use of aid programs, and cost of living introduced into the record by the Seniors and the OAG. Almost all LP customers have lower electric bills than they had six years ago, due to contract amendments allowing reductions in contract demand. Also, some LP customers have benefited from payments for released capacity under best efforts sales. The Commission must set rates which balance considerations of cost causation and other circumstances affecting customer classes.

Since an overall revenue decrease is being ordered in this proceeding, the Commission finds it undesirable to increase the rates for any class of customers unless a convincing need to do so is shown. The Residential class appears to be the customer group most below cost based solely on the results of the cost of service studies. However, the Commission has already found that the class cost of service study overstates the Residential, and other non-LP class, revenue responsibilities due to changes in LP usage patterns. The Commission finds the unreliability of the cost study results discussed previously, coupled with non-cost factors such as the economic situation of Residential customers in MP's service area, make it reasonable to maintain the Residential class revenues at the level existing before the rate case filing. The Commission finds that the LL&P, General Service, and Municipal Pumping class revenues should be maintained at their pre-filing levels.

The Lighting class and the LP class were shown to be paying rates in excess of cost even at the total revenue level used in MP's cost study; therefore, the Commission finds that rates for these two classes should be lowered to the extent permitted by the decrease in MP's total revenue requirement. The Commission finds it appropriate to give the Lighting class a $500,000 decrease, which is approximately the level of decrease originally proposed by MP. Finally, the Commission finds the remaining decrease, approximately $8 million, should be used to reduce the LP revenue level. This results in an overall revenue requirement for LP class approximately equal to what they would have received under MP's original proposal. The Commission notes that some members of the LP class will enjoy additional savings, due to the approval of an excess demand discount discussed in a subsequent section of this Order. The Commission finds that the class revenue responsibility described properly balances the results of cost studies with other cost and non-cost factors, producing just and reasonable rates for all customer classes. Based on the above findings, the Commission concludes that the Lighting class and the Large Power class should receive decreases in rate levels, while the present rate levels for all other customer classes are maintained.

The Commission will next address the issue of whether the revenue allocation and other rate design decisions made herein are binding on the Boswell 4 investigation proceedings.

In NSP, MP, E-002, 015/PA-86-722, the Commission approved MP's sale of 40% of Boswell 4 to NSP and established procedures for investigations of MP's rates on each of the three transfer dates. In its June 23, 1987 Order for Investigations in that docket, the Commission stated:

> Each of these three investigatory proceedings shall be limited in scope to the determination of the total Minnesota jurisdictional revenue requirement. If the jurisdictional revenue requirement shows that a negative revenue deficiency exists as of a transfer date, Minnesota Power shall adjust all retail rates retroactively to that transfer date, using the revenue responsibility allocations and rate designs approved by the Commission in Minnesota Power's last general rate case decided before that transfer date. . . .

MP and the Inland Group recommended that the Residential class revenue be "frozen" at the level set in this rate case, and not lowered if a decrease in MP's revenues were found appropriate as a result of the annual investigation proceedings. The OAG opposed freezing the Residential rate level.

The Commission finds that its Order in NSP, MP, E-002, 015/PA-86-722 contemplated that the revenue responsibilities and rate design decided in this, or an intervening, rate case would be controlling in the subsequent investigations. However, given the particular results of this rate case, which were not contemplated in the Boswell 4 transfer proceeding, the Commission finds it reasonable to reconsider its position and broaden the scope of the next investigation. The Commission has lowered rates for the two classes shown to be paying rates above cost, but has not made other changes in class revenue levels. Also, as discussed in subsequent sections of this Order, the Commission has foregone considering major changes in rate structures for most classes, since present revenue levels were maintained. Broadening the scope of the next Boswell 4 investigation proceeding will allow the Commission to review cost and non-cost factors and to further carry out the direction of this Order if appropriate. Therefore, the Commission concludes that class revenue allocation and rate design issues should be open to examination in the next Boswell 4 investigation proceeding.

B. Large Power Rate Design

1. Structure of Standard Large Power Rate

The issue before the Commission is the appropriate structure for the standard LP rate. The Commission's discussion is divided into five sub-sections: the service voltage adjustment, the energy charge level, the 100% billing demand proposal, the optional split demand charge, and the demand charge level. MP's excess demand discount proposal is discussed separately in the next section.

a. Service Voltage Adjustment

MP proposed to reduce very slightly the service voltage adjustment for service taken below 115 kV from $1.15 per kW of minimum capacity commitment (equivalent to $1.04 per billing kW) to $1.00 per kW. No party opposed this change. The ALJ did not make a specific finding on this issue.

The Commission finds MP's proposed change in the service voltage adjustment to be reasonable. There is no disagreement in the record concerning the proposal. The Commission finds the proposed discount is based on cost and will have a minimal impact on affected customers. Therefore, the Commission concludes the service voltage adjustment of $1.00 per kW should be adopted.

b. Energy Charge level

MP proposed an increase in the LP energy charge from 1.21 cents to 1.55 cents per kWh, primarily due to the roll-in of the fuel adjustment and inclusion of mine closing costs. The LP energy charge is designed to recover unit variable costs, with fixed costs recovered through LP demand charges. The DPS recommended approval of MP's proposed energy charge, with recovery of the rest of the LP revenue requirement through demand charges. The ALJ found MP's proposed energy charge to be appropriate and cost based.

The Commission finds the concept and structure of MP's energy rate to be reasonable. No party opposed the energy rate proposal. However, the Commission finds the final level of the rate must be reduced to recognize the partial disallowance of mine closing costs; the Commission will require MP to recalculate the level of the LP energy charge in its compliance filing. The Commission concludes that the concept of MP's proposed LP energy charge should be adopted, with appropriate adjustment for the mine closing cost disallowance.

c. <u>100% Billing Demand</u>

MP proposed to replace the present 90% minimum capacity commitment for determining billing kW with a 100% billing demand for rate simplification. The minimum capacity commitment in the present rate is equal to 90% of a customer's contract demand. The Inland Group stated that MP's proposal simplified application of the LP rate with no economic impact. The ALJ did not make a specific finding on this issue.

The Commission agrees with the Inland Group that MP's proposed change from the 90% minimum capacity commitment to a 100% billing demand merely simplifies the application of the LP rate and has no economic impact on customers. Instead of paying the old, higher rate on 90% of a customer's billing demand, a lower rate would be applied to 100% of billing demand. In its brief, Boise/Blandin opposed MP's proposal to increase the initial billing demand block from 90% to 100% and recommended no change to the current level of initial demand block. It appears to the Commission that Boise/Blandin is primarily opposing MP's rate increase for the first demand block and not the change to a 100% billing demand per se; the Commission addresses the demand blocks in sub-section e. The Commission concludes that MP's proposal to institute a 100% billing demand should be adopted.

d. <u>Optional Split Demand Charge</u>

MP originally proposed a split demand charge designed to relieve taconite processors from paying full demand charges for up to four months a year when their operations were shut down; the demand charge for usage over 10,000 kW would be lower when a customer was using 25% or less of contract demand, and higher when operating above that level. However, MP withdrew the proposal, since none of the LP customers supported it. MP's final proposal was a single demand rate for all demand in excess of 10,000 kW, to apply regardless of actual operating level.

The Inland Group proposed giving LP customers the option each year to elect either the single demand charge or a split demand charge. MP, the DPS, Eveleth, and Boise/Blandin all opposed the Inland Group's optional split demand charge proposal. The ALJ did not make a specific finding on this issue.

The Commission finds the proposal for an optional split demand charge to be unacceptable. If customers are permitted to elect which version of the rate they are on each year, only those intending to be shut down long enough to save money under the split demand rate would chose that option. Without the balancing effect from other customers paying a higher demand rate (as they would have under MP's withdrawn proposal), MP could clearly suffer a revenue shortfall if any customer chose the split rate. Also, implementation of an optional split demand rate would introduce greater uncertainty and variability into revenue recovery from the LP class. Therefore, the Commission concludes that the Inland Group's proposal for an optional split demand charge for LP customers should be rejected.

e. Demand Charge Level

MP proposed to increase the charge for the initial demand block in the LP rate by approximately 29%, from $115,800 for the first 9,000 kW of minimum capacity commitment to $149,100 for the first 10,000 billing kW. MP proposed to decrease the rate for all kW above the initial block by approximately 14%, from the equivalent of $17.86 per kW to $15.35 per kW. At MP's proposed LP class revenue level, the class as a whole would have received approximately a 4.5% decrease. However, due to the change in the demand rate structure, the impact on individual LP customers varied widely, with the four smallest LP customers receiving increases and other LP customers receiving decreases which were greater the larger the customer.

The DPS, the Inland Group, and LSPI supported MP's proposal. Potlatch opposed the level of MP's proposed increase in the first demand block and recommended instead that the increase in the block be the same as the overall increase to the LL&P class, and that no increase in the equilibrium load factor used to calculate the transition level between the LP and LL&P classes be permitted. Boise/Blandin recommended that the first demand block be maintained at the present rate level. The ALJ found that the charge for demand over 10,000 kW should be lowered as proposed by MP to provide needed relief to the taconite industry, improve MP's revenue stability, and move the LP class closer to its revenue responsibility. He found MP's proposal to raise the charge for the first 10,000 kW of demand reasonable and non-discriminatory since it was structured to reflect normal load factors and operating conditions of the taconite industry.

The Commission agrees with the ALJ that the charge for demand over 10,000 kW should be lowered to reflect the decrease in the revenue requirement for the LP class. However, the Commission does not agree that an increase of almost 29% in the first block of the rate is reasonable or justified on the record. While there is no obvious cost reason for setting the effective rate per kW for the first 10,000 kW significantly lower than for the remaining kW as in the present rate structure, there is a practical reason for at least some disparity between the blocks: the reasonable desire for a relatively smooth transition for customers who may be moving from the LL&P to the LP class.

The Commission finds that, in the absence of convincing reasons for adopting MP's proposal, the rate reductions for LP customers should be more uniform, so that all LP customers share more fairly in the revenue decrease to the class. The Commission agrees with Potlatch that MP has not shown a need to change the transition load factor of 56% used in the last rate case to the 62% level used in this case. However, the Commission finds that a movement toward decreasing the gap between the rates per kW in the two blocks is warranted for cost reasons as long as the impact on transition customers is reasonable. The Commission finds that a reasonable balance of interests among customers in the LP class would be achieved by increasing the rate for the first demand block by 10% over present rates and applying the decreased class revenue requirement to the tail-block. This rate structure will apply more uniformly than MP's proposal and will result in decreases for almost all LP customers. Therefore, the Commission concludes that the charge for the first 10,000 kW should be increased by 10% over present rates, and the balance of the revenue requirement not collected from that charge or the energy and voltage adjustment charges should be collected from the tail-block demand rate. MP will be directed to calculate the appropriate rates in its compliance filing.

2. Excess Demand Discount

The issue before the Commission is whether to approve an excess demand discount feature of the standard LP rate which gives a reduced rate for demand taken in excess of a customer's contract demand.

MP originally proposed an excess demand discount of $5.00 per kW, decreasing on each Boswell 4 transfer date and becoming zero in May 1991, for demand taken up to 110% of a customer's contract demand. MP later modified its proposal, based in part on suggestions by DPS and Inland Group witnesses. MP's final excess demand discount proposal would: 1) apply to all demand taken in excess of a customer's contract demand; 2) require 30 days advance notice and MP's approval for amounts from 110% to 120% of contract demand (and would require payment for requested demand whether this portion of the excess was actually used or not); and 3) remain at $5.00 per KW until a change is requested by MP and approved by the Commission. Excess energy would be priced at 110% of MP's incremental energy cost.

The DPS, the Inland Group, and LSPI supported MP's final proposal. Potlatch supported the proposal with the modification that 30 days advance notice not be required for use from 110% to 120% of contract demand. Eveleth opposed the excess demand discount. The ALJ recommended that the Commission adopt an excess demand discount for power up to 120% of contract demand, at a discount of $5.00 per kW, until a change is warranted. He found the proposed discount provides a potential for MP to derive revenues from plant that would otherwise remain idle and that having MP file a miscellaneous tariff when it believes a change is warranted allows flexibility and Commission oversight.

The Commission finds the excess demand discount in the final form recommended by MP makes sound economic sense, allowing MP an opportunity to sell some of its excess capacity and encouraging taconite industry production. The excess demand discount provides encouragement to LP customers to increase production if opportunities to sell their product are available, without penalizing the user with a permanent upward ratchet in contract demand. The discount provides MP with the potential to derive revenues from excess utility plant that would otherwise remain idle. The Commission finds a $5.00 per kW discount reasonable because the resulting rate recovers additional variable costs and helps provide some recovery of fixed costs that would otherwise be borne by MP or its ratepayers. The Commission finds that the excess demand rate is not discriminatory, as claimed by Eveleth, since it is available to all LP customers and does not by its terms exclude certain customers from using the rate. A rate that is available to everyone does not become discriminatory because a particular customer declines to use it.

The Commission agrees with Potlatch that MP's current excess capacity situation may allow the provision of power between 110% and 120% of contract without 30 days advance notice at some times. The Commission finds it reasonable to include a provision that would permit, but not require, MP to provide additional power from 110% to 120% of contract demand upon less than 30 days notice by a customer if MP is able. The Commission also finds it reasonable to require a customer to pay for this increment of power once requested, even if not used, since MP may have to purchase power or forgo sales it otherwise would make in absence of the commitment to the customer. The Commission concludes that MP's excess demand discount should be approved, with an added provision allowing demand from 110% to 120% of contract demand to be supplied on less than 30 days notice.

3. Weekly Billing

The issue before the Commission is whether all customers in the LP class should be billed weekly. Currently, the taconite members of the LP class are on weekly billing, but other LP customers are on standard monthly billing.

MP initially proposed weekly billing for LP customers in October of 1986; the Commission set the matter for hearing <u>In the Matter of the Request of Minnesota Power & Light Company for Authority to Change its Billing Procedures</u>, Docket No. E-015/M-86-641 (July 30, 1987), along with a similar proposal by Peoples Natural Gas Company. In that docket, MP proposed to protect itself and its other ratepayers from large bad debt expenses that could result from future bankruptcies of taconite companies or their owners by requiring LP customers to go on weekly billing if they exhibited certain negative financial indicators. A settlement was reached among the parties to the proceeding that would have applied weekly billing to all members of the LP class regardless of financial status, with a time value of money credit of two and one-half percent over prime. Boise and Blandin, who were not parties to the proceeding, objected to the settlement. In its July 30, 1987 Order Approving Settlement as Modified, the Commission directed that weekly billing apply only to the LP customers who signed the settlement (Hibbing, National, Inland, USX, Eveleth) and that the issue of weekly billing for the LP class as a whole be addressed in this general rate case.

MP proposed to make the weekly billing provision part of its standard LP rate schedule and apply it to all members of the LP class. The customer would be compensated for the time value of money compared to monthly billing by applying a credit at the prime rate plus two and one-half percent. The DPS and the Inland Group supported the MP proposal. Boise/Blandin and Potlatch opposed applying weekly billing to non-taconite LP customers. The ALJ found that MP did not make an evidentiary showing that Boise and Blandin are a sufficient credit risk to require weekly billing. The ALJ stated that weekly billing should apply only to those who have voluntarily accepted it.

The Commission agrees with the ALJ that weekly billing should continue for taconite producers, but not be imposed on the non-taconite members of the LP class. The bankruptcies of LTV Corporation, Erie Mining Company, and Reserve Mining Company, the closing of Reserve Mining facilities, the earlier closing of Butler Taconite Company facilities, and the general state of the taconite and steel industries presented in the record demonstrate that MP could face a very real risk of significant bad debt expense from its taconite-producing customers under traditional monthly billing. The Commission finds that the weekly billing method agreed to by the parties in <u>MP</u>, E-015/M-86-641 is reasonable for application to taconite LP customers because it recognizes MP's need for reduced exposure to extraordinary bad debt expense in the event of further bankruptcies of taconite companies while giving the affected customers an appropriate allowance for the time value of their early payments. All current taconite producing LP customers voluntarily agreed to these weekly billing terms in MP, E-015/M-86-641.

The Commission finds MP did not demonstrate on the record that the non-taconite members of the LP class presented sufficient bankruptcy risks that mandatory weekly billing should be imposed upon them. The Commission finds, however, that it is reasonable that new and existing non-taconite LP customers be given the option to elect weekly billing, since some customers may consider its terms to be beneficial. While the Commission agrees with the general proposition stated by the DPS that rates and conditions of service should apply consistently to all members of a customer class, the Commission finds that fairness considerations are overriding in this situation. Weekly billing is a specific solution for the limited problem of bankruptcy risk specific to the taconite members of the class. Should MP be able to establish in the future that non-taconite LP customers as a group or a specific customer pose substantial bankruptcy risk, MP could make a filing to the Commission to have mandatory weekly billing apply. Therefore, the Commission concludes that weekly billing should not be a requirement for all customers on the LP rate schedule; rather it should be mandatory only for taconite company customers.

4. Large Power Contract Length

The issue before the Commission is whether the requirement for LP customers to have ten-year contracts with MP should be made part of the standard LP rate schedule.

MP proposed making a ten-year contract with a four-year cancellation notice a requirement included in the standard LP rate schedule. Eveleth opposed requiring a new ten-year initial term contract for existing LP customers who let their contracts expire or take service under a short-term rate. Eveleth proposed that existing LP customers have contract terms of two years and one- or two-year cancellation notice requirements after completion of the initial ten-year terms of existing contracts. National witness Dudak recommended one-year extensions of LP contracts after expiration of the initial ten-year term and Potlatch witness Coldwell opposed applying a ten-year contract to an existing customer moving into the LP class. The ALJ did not make a specific finding on this issue.

The Commission finds there is no opposition to the requirement for ten-year initial term contracts with four-year cancellation notice provisions for LP customers who are new to the system, such as LSPI. MP has historically required such commitments. MP needs to plan for the generating capacity for the large requirements of such customers, and existing ratepayers need a degree of protection from potential revenue instability that could be present in the absence of long-term commitments.

The Commission has some sympathy with the arguments opposed to the ten-year contract requirement for a customer such as Potlatch whose incremental demand requirements are less than 10 MW or for customers who take service under the non-contract rate. However, the Commission finds that the overriding consideration is the need for revenue protection for MP and its other customers, especially given the large size of LP customers' loads compared to the size of MP's total system. Therefore, the Commission concludes that it should approve the inclusion of the ten-year initial term contract and four-year cancellation notice requirements in the standard LP rate schedule. However, recognizing that some situations could present convincing reasons for less restrictive requirements, the Commission concludes that these provisions should be subject to waiver with the approval of the Commission for good cause shown by the customer or MP. MP will be required to include such provisions in its compliance rate schedules.

5. Non-Contract Rate

The issue before the Commission is whether MP should offer a short-term alternative to the standard LP rate for customers who do not sign or extend long-term contracts.

MP first proposed a short-term rate for LP customers as a miscellaneous tariff in January 1984, which the Commission set for hearing along with the reasonableness of MP's LP demand ratchet in In the Matter of the Petition of Minnesota Power and Light Company for Authority to Establish a Short-Term Large Power Rate Schedule and of an Investigation into the Reasonableness of the Large Power Demand Ratchet, Docket No. E-015/M-84-29 (May 16, 1986). MP's proposed rate in that proceeding had a contract term of two years, a cancellation notice requirement of two years, and 20% demand charge and 10% energy charge premiums over the standard LP rate. In the event of a capacity shortage, MP would have provided service to its other customers before providing it to those on the short-term rate. The Commission rejected MP's short-term LP rate as proposed in MP, E-015/M-84-29, finding it was not adequately cost-justified as a separate interruptible type of service. The Commission recognized a possible need for a short-term rate, but concluded that the rate as then proposed did not address the needs of LP customers.

In this docket MP proposed a non-contract LP rate as an option for customers who are not able to enter into the standard long-term contract. The major features of the proposed non-contract rate are: 1) a contract demand charge 120% that of the standard LP rate; 2) an energy charge the same as on the standard LP rate; 3) a twelve-month 100% billing demand ratchet; 4) a one-year cancellation notice requirement; and 5) firm quality service. Excess revenues from the 20% demand premium would be spread to all other customers as a revenue credit on monthly bills. MP proposed to offer the rate until the final Boswell 4 transfer to NSP occurs in April 1991, when it would review its supply and demand situation to determine if the rate still made economic sense.

The DPS agreed with the concept of the non-contract rate proposed by MP, but recommended that the 20% demand charge premium be disallowed now, with annual filings to determine if a premium is needed. The Inland Group agreed with the DPS. Boise/Blandin and Eveleth opposed MP's proposal. The ALJ recommended adoption of MP's proposed non-contract rate. He found the 20% demand charge premium reasonable, in the absence of excess capacity, to recognize the costs imposed on MP from the lack of long-term commitments and to give proper price signals.

The Commission agrees with the ALJ that MP's non-contract rate proposal is reasonable, but disagrees with his statement on excess capacity. The Commission finds that it is reasonable to provide an alternative rate for LP customers who decline to commit to MP's standard long-term rate requirements. However, the Commission finds that there are costs to MP and its other ratepayers associated with the absence of long-term demand commitments from large customers, such as risks perceived by investors from uncertainty of the revenue stream. Lack of long-term commitments also make capacity planning decisions more difficult and potentially more costly. While the Commission agrees with the DPS that MP is not facing a capacity planning decision now, the increased risks perceived by investors and the long-term planning costs faced by MP still exist even in the presence of current excess capacity. Therefore, the Commission concludes that MP's proposed non-contract rate, including the 20% demand charge premium, should be approved.

6. Interruptible Rates

The issue before the Commission is whether MP should be required to develop and offer an interruptible rate to LP customers, and if so, when.

Taconite witness Baron proposed that MP develop a proposal for interruptible rates for LP customers within two years, for implementation no later than 1991, following the transfer of the final portion of Boswell 4 capacity to NSP. National witness Dudak recommended offering interruptible rates now, making them available to LP customers after they fulfill their original firm contracts. The DPS recommended that MP begin developing an interruptible rate for implementation when MP's supply and demand are in balance. The OAG opposed such a rate now, but recommended it as a precondition to adding new generating capacity or undertaking major long-term capacity purchases in the future. Eveleth recommended that the issue be studied by 1991. MP opposed developing an interruptible rate at this time. The ALJ adopted the DPS position.

The Commission agrees with the OAG that interruptible rates would not produce savings on MP's system at this time, due to MP's surplus capacity situation. Implementing interruptible rates now could cause firm customers to move to interruptible service, since the probability is high that little or no interruption would occur. This could be uneconomic for the system as a whole. Therefore, the Commission concludes that interruptible rates should not be implemented at this time. The Commission also agrees with MP that any interruptible rates developed now for implementation in 1991, or some unspecified future time, would involve inaccurate cost projections and speculative capacity assumptions. The Commission finds the OAG suggestion to be the most reasonable, given MP's current capacity situation and future uncertainty. Therefore, the Commission concludes that MP should develop and offer interruptible rates as a precondition to constructing new generating facilities or undertaking major capacity purchases.

7. Best Efforts Obligation

The issue before the Commission is whether the "Best Efforts" power marketing provision in LP contracts should be interpreted to apply not just to sales made by MP off-system, but to new sales to MP's retail and wholesale customers as well. A secondary issue is how revenues from off-system sales should be shared between MP and its LP customers.

Eveleth first raised the best efforts issue in its petition for rehearing in In the Matter of the Petition of Minnesota Power & Light Company to Amend Temporarily the Contract Demand Level in the Electric Service Agreement of Hibbing Taconite Joint Venture, Docket No. E-015/M-87-261 (May 29, 1987), where the Commission approved a temporary amendment allowing Hibbing to take power in excess of 120% of its contract demand without establishing a new permanent contract demand level for the remainder of its contract. Eveleth argued that MP had an obligation to market Eveleth's excess power to Hibbing and to credit Eveleth for these sales. In its July 10, 1987 Order Denying Reconsideration in MP, E-015/M-87-261, the Commission found that Eveleth's arguments did not go to the merits of the sale of additional power to Hibbing, but rather to the interpretation and application of the best efforts marketing provisions in LP contracts. The Commission found that Eveleth had raised issues which merited further review in a forum which would provide additional information and broader participation, and directed that the best efforts issue be addressed in this general rate case.

Eveleth contended that the best efforts obligation contained in LP contracts is unlimited and unqualified, and therefore extends to any new large sale of power by MP, including sales to new and existing retail and wholesale customers. MP argued that its best efforts obligation applies only to off-system sales and was never intended to apply to sales which the Company would have otherwise made to its retail or wholesale customers. The DPS agreed with MP and recommended that the Commission look to historical interpretations of the provision and the implications of various interpretations in reaching its decision. The Inland Group proposed a demand marketing rider which would supplant any obligation of MP to market power to retail customers under best efforts; this proposal is discussed in the following section. The ALJ rejected Eveleth's interpretation, finding that the best efforts obligation was limited by contract and practice to off-system sales and that any other interpretation would increase the revenue deficiency for all customers and restrict MP's ability to deal with its surplus capacity.

The Commission will first look to the language of the best efforts obligation. This obligation first appeared in LP contracts in 1975. MP now has the following provision included in all LP electric service agreements:

> In the event that Customer's power requirements will be significantly reduced for an extended period of time and Customer advises Company of the amount and duration of the reduction, Company will exert its best efforts to market the unused power. Company will then determine the credit due Customer from the sale of such power and adjust Customer's billing accordingly.

The Commission finds that the best efforts language is general and does not by itself answer the question of whether the best efforts obligation applies to on-system sales. The Commission believes that MP should have taken more care in drafting the best efforts language to make its intended scope and application clear.

The Commission disagrees with Eveleth's contention that the parol evidence rule precludes consideration of other evidence of the intent of the parties to the contract and past practice. In addition, even Eveleth would add to the "plain" meaning of the language by qualifying that it applies only to sales of large amounts of power, setting a floor on the size of a qualifying sale, not applying it to customers for whom capacity had been constructed or specifically contracted for, and specifying a crediting mechanism. The Commission need not reach the issue of whether such qualifications would be necessary and reasonable if it were to adopt Eveleth's interpretation, since Eveleth's qualifications negate its own argument that the contract language is plain and unambiguous on its face.

The Commission finds it reasonable to look to the interpretation the parties have given this contract provision in the past and to the public interest considerations of various interpretations to reach a determination on this issue. The Commission finds that the parol evidence rule does not bar the consideration of extrinsic evidence in this matter. In essence the parol evidence rule provides that the contract itself is the sole basis for its interpretation. Going beyond the "four corners" of the document to determine the intent of the contracting parties is not allowed. "[T]his rule requires, in the absence of fraud, duress, mutual mistake, or something of the kind, the exclusion of extrinsic evidence, oral or written, when the parties have reduced their agreement to an integrated writing." 4 Williston § 631.

While the parol evidence rule is one of substantive contract law,
courts have recognized a number of exceptions to it. When the written agreement's terms are ambiguous or uncertain, parol evidence can be considered to determine a correct interpretation of the contract. Also, analysis of the past performance of the parties to the contract and the public interest implications of various interpretations of the best efforts clause can aid the Commission in construing it. Course of performance refers to the parties' conduct following a contract. The principles of the Uniform Commercial Code, although not directly applicable, offer some guidance. According to the Code: "[W]here the contract for sale involves repeated occasions for performance by either party with knowledge of the nature of the performance and opportunity for objection to it by the other, any course of performance accepted or acquiesced in without objection shall be relevant to determine the meaning of the agreement." U.C.C. § 2-208(1). Minn. Stat. § 336.2-208(1) (1986).

The Commission finds that the best efforts provision has always been interpreted by MP to apply only to off-system sales and has been implemented by MP only through off-system sales since the provision was first applied to give a credit to Hanna Mining Company in 1976. Furthermore, no LP customer has complained to the Commission about MP's practice until Eveleth did so in June 1987 in MP, E-015/M-87-261, even though MP made new retail sales between 1976 and 1987; under Eveleth's interpretation, these new sales should have been subject to the best efforts obligation and credited to LP customers. The Commission considers this lack of comment by other LP customers as an indication that they understood the best efforts clause to be limited to off-system sales. In addition, the Commission agrees with MP and the DPS that the "right to assign" provision requested by Inland and included in its 1986 contract amendment, and subsequently in certain other LP contracts, would likely not have been considered necessary by these customers had they considered the best efforts provision to apply to on-system retail sales. The Commission concludes that past practice supports the limitation of the best efforts provision to off-system sales.

The Commission has also considered the public interest and the effects on MP customers of different interpretations of the best efforts provision. Under Eveleth's interpretation, new power sales made by MP would be credited to LP customers who released capacity, rather than to the cost of service for all ratepayers; only after all LP excess power was used up would other ratepayers benefit from expanded power sales. This has the potential for considerable negative impacts on other customers. In this rate case, over $6 million of excess demand revenues are included in the test year, as well as more than $11 million of additional sales to LSPI and Potlatch. Under Eveleth's interpretation, LP customers who have released power (Eveleth) would apparently receive all the benefits up to the amount of power released and only then would the general body of ratepayers share in the revenues from these increased sales. The Commission concludes that public interest considerations support the limitation of the best efforts provision to off-system sales.

Based on the analysis above, the Commission agrees with the DPS and the ALJ that Eveleth's interpretation of the best efforts obligation should be rejected. The Commission concludes that the best efforts provision in LP electric service agreements should apply only to off-system sales.

The Commission will also address the issue of the appropriate method for crediting off-system sales revenues. Eveleth argued that MP's 1983 to 1987 policy of sharing credits for all off-system sales between MP and LP customers releasing capacity should be maintained. The other parties and the ALJ did not address this issue.

MP has been crediting a customer for sales off-system made as a result of that specific customer's release of capacity. Prior to 1983, MP pursued sales for its own account also, independent of capacity releases by LP customers. Pursuant to a February 23, 1983 MP memorandum sent to LP customers, one-third to one-half of any off-system sales demand revenues were available for allocation to LP customers who had released power from January 1983 through October 1987. It was not clear on the record what policy MP intended to follow after October 1987. MP did not file its policies and procedures on crediting best efforts revenues with the Commission.

The Commission agrees with Eveleth that MP should maintain its 1983 to 1987 policy of sharing demand revenues from any off-system sales with all LP customers who have released capacity. The Commission finds there is no practical and objective means to determine which sales are made for MP's own account and which are made due to a capacity release by customers. A policy of crediting one-half of the demand revenues from off-system sales to LP customers who have released capacity reasonably balances the interests of MP and its customers. If, as seems likely, LP customers now have little or no capacity to release, then MP will retain all, or the majority of, the benefits from off-system sales; if LP customer later have capacity to release, they will be able to share in the benefits. Therefore, the Commission concludes that MP should maintain its 1985 to 1987 policy of crediting one-half of the demand revenues from any off-system sales to LP customers who have released capacity. The Commission will require MP to file its policy for Commission approval and inclusion in its tariff book. If the Company wishes to change its policy in the future, MP must file for Commission approval before doing so.

8. Demand Marketing Rider

The issue before the Commission is whether to approve a demand marketing rider, which would allow LP customers to sell unused portions of their contract demand to other LP customers.

The demand marketing rider proposed by the Inland Group would permit LP customers to sell their excess contract demand to other LP customers at a "split the savings" price for a minimum period of one month. The split the savings price would be 50% of the buyer's cost to purchase the power under MP's applicable demand rate instead, since the cost to the seller was assumed to be zero. This proposal was intended to supplant any best efforts obligation MP may have to market excess LP demand to retail customers. MP, the DPS, and Eveleth opposed the proposal. The ALJ rejected the Inland Group's proposed demand marketing rider, finding that it was not revenue neutral to MP. The ALJ stated that as long as one LP customer had excess contract demand, MP would derive no additional revenues from a new sale of power.

The Commission agrees with the DPS and the ALJ that the demand marketing rider is not revenue neutral to MP and other ratepayers and inappropriately gives the marketing of LP customer's excess demand priority over MP's ability to sell its own excess capacity. As long as one LP customer has unused capacity, MP and its other ratepayers would derive no additional revenue from a new sale of power to the LP class. The Commission finds that it would be unreasonable for LP customers to receive the competitive advantage to sell their capacity at a price below that at which MP can sell its capacity, since the LP customers' own contract demand reductions contributed to the excess capacity situation. Therefore, the Commission concludes that the demand marketing rider proposed by the Inland Group should be rejected.

C. Other Class Rate Design

1. Residential Rates

The issue before the Commission is the appropriate structure for Residential rates, including the level of the customer charge and the differential between energy charge blocks.

MP's current Residential rate has a customer charge which includes the first 50 kWh of energy. MP proposed to increase the minimum charge by 90 cents per month, bringing the charge in rate areas I, II and III to $4.90, $4.95 and $5.00 respectively. The DPS accepted MP's proposed customer charge. The OAG recommended that the existing minimum charge be retained. The Seniors recommended a "pure" customer charge of $2.00 with no energy included. The ALJ recommended that MP's proposed customer charge for the Residential class be adopted because the increase moved the charge toward cost.

MP's current Residential rate has three energy rate blocks: a relatively low rate for the first 300 kWh (after the 50 kWh included in the customer charge), a higher rate for the next 350 kWh, and a lower rate for all additional kWh. MP proposed a 15% increase in all energy rate blocks. The DPS recommended reducing the rate block differential by one third, in a partial movement toward flat rate energy charges. The OAG also proposed movement toward flat energy rates, by reducing the differential between the middle and tail blocks. The Seniors recommended a two-block Residential rate: the first 350 kWh (lifeline block) priced at the same overall level as existing rates, and all additional kWh at a flat rate. The ALJ recommended that the declining-block structure for the Residential class be retained, with a reduction in the differential between blocks of up to 20%, in order to have charges better reflect cost but not to have too large an impact on higher-use Residential customers.

The Commission finds that it is appropriate to maintain the Residential rate structure as it was prior to the filing of the rate case, since the present revenue level is being maintained for this class. The decision to retain the present structure of Residential rates should not be interpreted as a rejection of the merit of the issues raised by parties; the Commission believes that arguments on the appropriate customer charges and rate blocks as well as the possibility of reducing the number of rate areas, would have been worthy of serious consideration under other circumstances. However, the Commission finds that it would create unnecessary customer misunderstanding and confusion to consider substantial changes in the rate structure, with the possibility of rates for some customers increasing noticeably, when no rate increase has been given to the class. Therefore, the Commission concludes that the present Residential rate structure should be maintained.

2. Service Voltage Discounts

The issue before the Commission is whether to approve voltage discounts for the Large Light and Power, General Service, and Municipal Pumping classes.

MP proposed that the discount for High Voltage Service in the LL&P, General Service, and Municipal Pumping rate schedules be increased from $0.50 per kW to $1.00 per kW for customers taking service at 13,000 volts to 115,000 volts and that a discount for Transmission Voltage Service of $1.00 per kW and 0.242 cents per kWh be added for customers taking service above 115,000 volts. DPS recommended acceptance of MP's proposed voltage discounts because they were based upon cost. The ALJ concurred in the proposed voltage adjustments.

The Commission finds that it is reasonable to maintain the present service voltage discounts, since the Commission is not changing the present revenue levels for these three classes. It could cause unnecessary disruption and confusion to implement new voltage discounts, because other elements of the rate structure would have to change to maintain the present class revenue levels. The Commission's decision should not be interpreted as rejecting the merits of MP's proposal. Therefore, the Commission concludes MP's proposed voltage discounts for the LL&P, General Service, and Municipal Pumping classes should not be adopted at this time.

3. Large Light and Power Rates

The issues for Commission decision are whether to change the structure of LL&P rates and whether to convene a study group to explore alternative LL&P rates.

MP proposed that the rate structure for the LL&P class remain basically unchanged, with demand and customer charges increased slightly more than energy charges to move rates toward unit costs. MP proposed that the customer charge component included in the rate for the first 100 kW of demand be increased from $125 per month to $145 per month. The DPS recommended increasing the customer charge component to $150 per month and that the remaining increase be made up by equal percentage increases in the demand and energy charges. The ALJ recommended that MP's proposed increase in the customer service charge be adopted and any remaining revenues be made up by equal adjustments in the demand and energy charges.

The Superwood Group recommended that the Commission order the DPS and MP to convene a group, including interested LL&P customers, to recommend to the Commission alternative LL&P rates which would better utilize MP's excess capacity and more fully utilize customer production capacity and resources. MP witnesses opposed formation of a study group. The ALJ stated that a study group for the examination of LL&P rates would not be appropriate because MP does not currently have excess capacity.

The Commission finds that it is reasonable to maintain the LL&P rate structure as it was prior to the filing of the rate case. Since the present revenue level is being maintained for this class, it could create unnecessary customer disruption to consider rate structure changes. The Commission concludes the present LL&P rate structure should be maintained.

The Commission finds that a study of alternative LL&P rates would not be productive at this time. The option to choose between the LL&P and General Service rates, the relatively low demand charges and less restrictive terms compared to Large Power rates, and the stability in the overall level of LL&P rates provide benefits and flexibility to customers in the LL&P class. Also, as noted in the discussion of interruptible rates for Large Power customers, the Commission does not believe that such rates would be appropriate for development now, due to the lack of system savings likely to result. As MP's capacity situation and other system circumstances change in the future, further investigation of interruptible, time-of-use, and other rate alternatives may be appropriate. Therefore, the Commission will not order a study group on alternative LL&P rates at this time.

4. General Service Rates

The issue before the Commission is the appropriate structure for General Service rates.

MP proposed that the General Service rates remain basically unchanged, with customer and demand charges increased slightly more than the energy charge in an effort to move this class toward unit costs. The DPS agreed with MP's rate structure proposal. MP stated that there would be substantial revenue erosion due to customer crossover to General Service from the LL&P class at the relative class rate increases it proposed, because low load factor LL&P customers would find it economic to move into General Service class. MP estimated that there would be a $500,000 revenue loss from this crossover and proposed to assign this amount to the General Service class revenue requirement. The ALJ concurred in the MP and DPS recommendations on the General Service class rate structure and recommended approval of assigning any crossover revenue to the General Service class, since there was no objection to MP's proposal.

The Commission finds that it is appropriate to leave the General Service rate structure as it was before the rate case was filed. Since the present revenue allocation is being maintained for this class, it could create unnecessary customer confusion to make changes in the present structure. The Commission also finds that it is not necessary to assign any revenue responsibility from the Large Light and Power class to the General Service class; there will be no change in the present rate levels of these classes, and thus no additional incentive for low load factor LL&P customers to cross over to General Service to obtain economic rates. Therefore, the Commission concludes that the present General Service rate structure should be maintained.

5. Municipal Pumping Rates

The issue before the Commission is the appropriate rate structure for Municipal Pumping customers.

MP proposed increasing the customer charge for all Municipal Pumping customers from $3.35 to $3.85. For demand metered customers, MP proposed increases in both the demand and energy charges and for non-demand metered customers, a small increase in the energy charge, making the rate quite similar to the non-demand metered General Service rate. MP stated its intention to phase out the Municipal Pumping rate, but felt the billing impact on demand metered customers would be too great to do so at this time. The DPS recommended acceptance of MP's proposed customer charge and proposed that the remaining revenues be applied equally across demand and energy charges. The DPS argued that if MP proposes to discontinue this rate in a future case, MP should be required to provide justification for doing so, since both the MP and DPS cost studies show differences in costs between General Service and Municipal Pumping. The ALJ did not make a finding on the rate structure for this class.

The Commission finds that it is appropriate to leave the Municipal Pumping rate structure as it was before the rate case filing. Since the present revenue level is being maintained for this class, it could create unnecessary customer confusion to make changes in the rate structure. The Commission agrees with the DPS that if MP proposes to discontinue the Municipal Pumping Rate in a future rate case, MP must provide more justification for doing so than is present in this record. Such additional information should include, but not necessarily be limited to, the rate impact on customers, a showing of cost differences, and any additional rationale for the discontinuation. The Commission concludes that the present Municipal Pumping Rate structure should be maintained.

6. Lighting Rates

The issue for Commission decision is the appropriate rate structure for lighting customers.

The Company proposed to close rate schedules for new installations of fluorescent and mercury vapor lamps in recognition of the higher efficiency of sodium vapor lamps, which are now being installed as standard equipment. MP also proposed that incandescent lamps be removed from all lighting schedules except ornamental service. DPS agreed with MP's proposals (although not toally with the revenue allocation), as did the ALJ.

The Commission notes that it has reduced the revenue level for the Lighting class by $500,000. The Commission finds MP's proposals reasonable, because they recognize the higher efficiency of sodium vapor lamps, which are now being installed as standard equipment. The Commission encourages the promotion of inexpensive means for improving energy efficiency. The Commission concludes that MP's proposed rates for the Lighting class should be adopted.

7. Time-of-Day and Load Control Rates Study

The issue before the Commission is whether to order a feasibility study of time-of-day and load control rates on MP's system.

The DPS recommended that the Commission order MP to work with its customers to determine the feasibility of load control devices and time-of-day rates and to file a report with the Commission, including specific rate proposals, in one year. The ALJ found that the DPS suggestion should not be adopted at this time, since MP has little peak demand and its load factor is relatively constant, and that load control devices and time-of-day rates are more applicable to utilities whose load patterns are more volatile than those of MP.

The Commission agrees with the ALJ and finds that the DPS suggestion of a study for time-of-day and load control rates should not be adopted at this time, since it was not demonstrated on the record that such a study was likely to be fruitful, given MP's high load factor. However, if exploration of load control alternatives is later shown to be appropriate, it may be more properly considered under some other procedure such as CIP. Therefore, the Commission will not order a study of time-of-day and load control rates at this time.

D. Conservation Plan

The next issue is whether to accept MP's Conservation Plan.

Minn. Stat. § 216B.16, subd. 1 (1986) requires utilities meeting certain requirements to include an energy conservation plan in a filing for a general rate increase. MP submitted a conservation plan as Attachment C to the Direct Testimony of A.D. Harmon.

The DPS recommended that MP should:

1) Use the Minimum Revenue Requirement test to evaluate cost-effective conservation programs and consider examining conservation programs from a number of perspectives when considering which programs to implement.
2) Provide a study of expected impact of conservation programs on the Company's sales, peak demand and revenue requirements; and
3) Resubmit its Conservation Improvement Plan with a clear and specific statement of the Company's goals and objectives;

MP argued that its conservation plan, as submitted, describes an effective, ongoing conservation planning process which identifies electric end uses and conservation barriers to meet identified needs and evaluates the cost-effectiveness of the proposed program by using the Avoided Capacity Cost model.

The ALJ recommended that the DPS recommendations be adopted and that MP be required to make its revised filing within 90 days.

The Commission will not accept the DPS recommendation at this time. The Commission finds that MP's conservation plan should be fully evaluated in the context of the review of MP's upcoming May 1, 1988 Conservation Improvement Program filing pursuant to Minn. Rules, part 7840.0500. In addition, cost-effectiveness tests are currently being addressed by a DPS-utility task force. The Commission concludes that it is necessary to coordinate the review of MP's overall conservation planning with a review of the proposed conservation programs. The Commission may require MP to make appropriate changes to its Conservation Plan at that time.

XIV. REFUNDS

The threshold question is whether the Commission has authority to order refunds below the level of rates existing prior to the rate case filing. This question arises because the final MP revenue requirement authorized by the Commission is lower than the level of rates in effect prior to the rate case filing. The Commission has not addressed this issue under the current interim rates statute.

The DPS, the OAG, the Inland Group, and Eveleth all asserted that the Commission has the authority to order MP to refund the full difference between the overall interim rate level and final rate level. MP claimed the Commission lacks statutory authority to require refunds below the level of the rates existing at the time of the rate case filing. MP further argued that even if the Commission has such authority, it should not require additional refunds for equitable reasons.

Minn. Stat. § 216B.16, subd. 3 (1986) provides:

> If, at the time of its final determination, the commission finds that the interim rates are in excess of the rates in the final determination, the commission shall order the utility to refund the excess amount collected under the interim rate schedule, including interest on it which shall be at the rate of interest determined by the commission.

MP mistakenly maintains that this statute is not materially different from the statute which the Commission interpreted in Minnesota Power & Light Company, Docket No. E-015/GR-76-408 (December 18, 1976) to allow a refund only between the level of rates under bond and the prefiling rate level.

The Commission need look no further than the difference between the language of the statute before it was amended in 1982, and after, to realize that the Legislature clearly intended to grant the Commission authority to award refunds below existing rates. Before 1982, the statute provided for an interim increase in rates when a company filed a bond "conditioned upon the refund, in a manner to be prescribed by the commission, of the excess in increased rates,..., collected during the period of the suspension if the schedule so put into effect is finally disallowed by the commission." The language the Legislature used there clearly referred to a difference between prefiled rates and interim rates, not interim and final rates. The 1982 amendment changed that language to require a refund of the excess between the interim and final levels. This change in the statute can only be interpreted to mean that the Legislature changed the refund provision to allow for refunds of the excess of interim rates over final rates as opposed to the excess of interim rates over pre-filing rates. Therefore, the Commission's decision in MP's 1976 rate case is inapplicable to this proceeding.

Based on the analysis above, the Commission concludes that Minn. Stat. § 216B.16, subd. 3 (1986) unequivocally provides for a refund of the difference between the revenue requirement set in the interim order and the revenue requirement set in the final order, rather than the difference between the rates before the filing and the interim rates as contended by the Company.

The next question to be considered is whether equitable considerations justify the Commission requiring MP to make some lesser refund than provided for in the statute.

MP maintained that the Commission's refund calculations should be tempered by the facts in this record and by equitable considerations. MP argued that the Commission's final revenue requirement incorporates cost reductions occurring after the test year which should not be recognized in interim rates.

The Commission finds that MP's request is merely an attempt to reargue its position on the appropriateness of determining two revenue deficiencies in this proceeding. The Commission has rejected MP's arguments for the reasons stated in Section VII, Two Revenue Deficiencies. Therefore, the Commission will require MP to refund to its customers the entire difference between the overall interim and final revenue levels.

The final question to be considered by the Commission is how the refund monies should be distributed among customer classes.

In its June 30, 1987 Order Setting Interim Rates, the Commission found an interim revenue deficiency under present rates of approximately $4.8 million, which it directed be apportioned equally to all classes of customers. The Commission also authorized MP to forgo collecting the applicable interim increase from any class of customers, with the condition that any refund of excess interim rates be returned only to those classes who actually paid increased interim rates. MP applied an interim increase of 1.65% over present rates to all other classes, but did not collect any interim increase from the LP class.

The Commission finds that under the interim rates statute, all customer classes should receive an equal percentage refund of the difference between the interim and final rate levels. The Commission has consistently followed this practice and its interpretation has been upheld by the Minnesota Supreme Court. See <u>In re Petition of Inter-City Gas Corporation for Authority to Change its Schedule of Rates for Gas Service in Minnesota</u>, 389 N.W. 2d 897 (Minn.1986); <u>In the Matter of the Application of Peoples Natural Gas Company for Authority to Increase rates for Gas Utility Service in Minnesota</u>, 389 N.W. 2d 903 (Minn. 1986). The practical implementation of this policy is complicated somewhat in the circumstances of this case, however, because MP did not collect an increase over present rates from the LP class.

The Commission finds that it is clear that the LP class is not entitled to any portion of the refund attributable to the difference between present and interim rate levels, since LP customers did not pay an increase over present rates during the interim period. Interim rates for the LP class are equal to present rates. However, the Commission finds that LP customers are entitled to share in the refund attributable to the difference between present rates and the final rate level proportionately with all other customers. If MP had applied the 1.65% interim increase to the LP class as it did to all other classes, then all classes including LP would have received an equal percentage refund.

The Commission's determinations fairly return the overall difference between interim and final rate levels to all customer classes, are consistent with the intent of Minn. Stat. § 216B.16, subd.3 (1986), are consistent with Commission policy in other rate cases for other utilities, and implement the decisions in its Order Setting Interim Rates in this docket. Based on the above discussion, the Commission will require MP to file a refund plan which returns the portion of the interim rate level which exceeds the present rate level only to those classes who actually paid increased interim rates and returns the balance of the difference between the final and interim rates levels proportionately to all customer classes.

ORDER

1. Minnesota Power shall decrease gross annual revenues from Minnesota sales of electricity by rate class by $8,500,076 to produce annual gross revenues from Minnesota sales of electricity by rate class of $276,642,727.

2. Within 20 days of the issue date of this Order, Minnesota Power shall file with the Commission for its review and approval a schedule of revised rates, charges, and tariffs, with supporting documentation and calculations, based on the revenue requirement authorized herein, including:

   a. maintenance of the present (pre-filing) rate levels and rate structures for the Residential, General Service, Municipal Pumping, and Large Light & Power classes;

   b. a reduction of approximately $500,000 for the Lighting class with the rate design changes approved herein;

   c. a reduction of approximately $8 million for the Large Power class with the rate structure changes approved herein, including a 10% increase in the demand charge for the first 10,000 kW and a decreased demand charge for all additional kW;

   d. the addition of a Large Power excess demand discount rate;

   e. mandatory weekly billing for taconite-producing Large Power customers, with optional weekly billing for non-taconite Large Power customers;

   f. inclusion of ten-year initial term contracts and four year cancellation notice provisions in the Large Power rate schedule, with a provision for waiver;

   g. the addition of a Large Power non-contract rate;

   h. a policy for crediting off-system sales under the best efforts obligation.

3. Within 30 days of the issue date of the Order, the Company shall file with the Commission for its review and approval a proposed plan for refunding to all customers the revenue collected during the interim rates period in excess of the revenue requirement authorized herein, as discussed in Section XIV.

4. Minnesota Power shall serve on all parties to this proceeding copies of the filings required in Ordering Paragraphs 2 and 3 above. Parties shall have 15 days to comment on these filings.

5. Within 30 days of the issue date of this Order, Minnesota Power shall file with the parties and

serve on the Commission, with its revised rates and charges, a revised base cost of fuel and supporting schedules, incorporating the changes made herein. Minnesota Power shall also file a fuel clause adjustment establishing the proper adjustment to be in effect at the time final rates become effective. Parties shall have 15 days to comment on these filings. The DPS shall review these filings in the same manner as any other automatic adjustment filings submitted to them.

6. As discussed herein, Minnesota Power has satisfied the intent of the Commission's rules relating to rate adjustments due to the Tax Reform Act of 1986. Further filings shall not be required under Minn. Rules, parts 7827.0100 to 7827.0600.

7. On or before January 1, 1989, Minnesota Power shall file with the Commission, and serve on all parties, a conservation cost recovery report of activities for the 15-months ending September 30, 1988. The report shall contain a summary of the following items: (1) the revenues collected under the conservation cost recovery charge, (2) an itemization by program cost of the conservation expenses incurred by Minnesota Power for the Commission-approved CIP costs, and federally-required program costs which Minnesota Power placed in the conservation cost tracker account, and (3) separate itemization of item (1) and (2) for the three-month period ending September 30, 1987. The same report is required annually thereafter except subsequent reports will cover the 12-month period ending the preceding September 30 and item (3) will not be required.

8. Within 45 days following the issuance of the FERC's final decision in its Docket No. FA-84-15-000, regarding the litigation expenses included in the fuel adjustment clause as discussed herein, Minnesota Power shall file with the Commission, and serve on all parties, its compliance filing including copies of the FERC decision, full detail of the costs at issue, and Minnesota Power's testimony stating its position on the matter before the Commission. Parties shall have 30 days from the date of the compliance filing to make comments to the Commission.

9. Within two years of the issuance of this Order, Minnesota Power shall file with the Commission, and serve on all parties, its updated proposal for the treatment of post-shipment mine closing costs which addresses the concerns described herein. Minnesota Power shall maintain detailed records sufficient to identify the amount of post-shipment mine closing costs collected through rates accumulated in the sinking fund, including interest at the after-tax cost of capital determined in this proceeding.

10. On or before March 1, 1989, Minnesota Power shall file with the Commission, and serve on all parties, the detailed rate case expense documentation as discussed herein.

11. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mary Ellen Hennen
Executive Secretary

(S E A L)